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VOLUME I.

TRANSCRIPT OF RECORD

SUPREME COURT OF THE UNITED STATES

OCTOBER TERM, 1941

No. 265

FEDERAL POWER COMMISSION AND ILLINOIS COMMERCE COMMISSION, PETITIONERS

vs.

NATURAL GAS PIPELINE COMPANY OF AMERICA AND TEXOMA NATURAL GAS COMPANY

No. 268

NATURAL GAS PIPELINE COMPANY OF AMERICA AND TEXOMA NATURAL GAS COMPANY, PETITIONERS

vs.

FEDERAL POWER COMMISSION AND ILLINOIS COMMERCE COMMISSION

ON WRITS OF CERTIORARI TO THE UNITED STATES CIRCUIT COURT OF APPEALS FOR THE SEVENTH CIRCUIT

Petitions for certiorari filed July 12, 1941, July 14, 1941

Certiorari granted October 13, 1941

IN THE

United States Circuit Court of Appeals
For the Seventh Circuit

No. 7454

NATURAL GAS PIPELINE COMPANY OF AMERICA
AND TEXOMA NATURAL GAS COMPANY,
Petitioners,

vs.

FEDERAL POWER COMMISSION AND ILLINOIS
COMMERCE COMMISSION,
Respondents.

Petition for Review of Interim Order of the Federal Power Commission.

INDEX.

Petition of the Illinois Commerce Commission, filed with the Federal Power Commission, September 23, 1938 1

Order of Federal Power Commission instituting Investigation, entered October 14, 1938 6

Answer of Natural Gas Pipeline Company of America and Texoma Natural Gas Company to Petition, filed November 16, 1938 9

Order fixing date of hearing, entered April 14, 1939 ... 13

PROCEEDINGS AT HEARING.

Statement by Examiner 15

Statement by Mr. Morgan 16

Colloquy 25, 33, 64

Statement by Mr. Booth 28

Statement by Mr. May 31

ABSTRACT OF TESTIMONY.

Witnesses for Federal Power Commission.

Testimony of:

Brown, Claude C. 35, 36

Knapp, Charles W., Jr. 2004, 2103, 2588

Smith, Charles W. 2041, 2222, 2632

Witnesses for Illinois Commerce Commission.

Testimony of:

Kleinman, Fred 2075, 2382

Ostrander, E. D. 1977, 2277

Woodford, John M. 57, 393

Vol. I, pp. 1 to 646; Vol. II, pp. 647 to 1310; Vol. III, pp. 1311 to 1976; Vol. IV, pp. 1977 to 2672; Vol. V, pp. 2673 to 3031; Vol. VI, pp. 3033 to 3417; Vol. VII, pp. 3419 to 3902; Vol. VIII, pp. 3903 to 4022.

Witnesses for Defendants.

Testimony of:

Biddison, P. McDonald.....1041, 1284
Brainard, W. F.....481
Brown, Floyd C.....491, 1311, 1636
Bulla, W. T.....987
Bussard, R. M.....715, 854, 1056
Campbell, S. E.....1003, 1398, 2554, 2637
Cooke, John A.....1446, 1909, 2616, 2669
Cottingham, V. E.....187
Davidson G. M.....1013, 1040, 1068, 1142
Davidson, W. H.....815
Delafield, Robert H.....1415, 1753, 2558, 2657
Dickinson, J. G.....613, 874, 1379
Dorau, H. B.....1512, 1636, 1788, 1965, 2527
Eastman, H. L.....1210
Emery, J. A.....1324, 1451, 1638, 1690, 1927
Foster, M. E.....1110
Galloup, Charles I.....453
Gill, Stanley.....361, 1024
Gillman, William C.....
.....1471, 1678, 1702, 1867, 2469, 2600, 2671
Hamilton, F. C.....1191, 1271
Hammerschmidt, E. G.....465
Hughes, C. Don.....315
Kesinger, E. V.....647, 2596
Miller, S. L.....1340, 1383
Palyi, Melchoir.....398
Parker, R. D.....249
Peterson, C. J.....192, 359
Powers, R. T.....767

Vol. I, pp. 1 to 646; Vol. II, pp. 647 to 1310; Vol. III, pp. 1311 to 1976; Vol. IV, pp. 1977 to 2672; Vol. V, pp. 2673 to 3031; Vol. VI, pp. 3032 to 3417; Vol. VII, pp. 3418 to 3902; Vol. VIII, pp. 3903 to 4022.

Testimony of:

Smith, W. D. 1119
Solow, E. M. 1167, 1859
Stoddart, Frank W. 1259
Strong, R. G. 903
Taubman, Herman P. 1148, 1190
Thompson, J. D., Jr. 275
Wallace, R. J. 1341
Willard, J. L. 1240
Zwiener, K. V. 1367

EXHIBITS.

No.

3 Production and B.T.U. by Fields Texoma Company for year ending June 30, 1938 (F. P. C.) ..2673
4 Gas sold or delivered, Texoma Company for year ending June 30, 1938 (F. P. C.) 2674
5 Texoma Company Consolidated Operating Analysis, etc. (F. P. C.) 2675
6 Texoma Company earnings analysis, 1934 to 1938, inc. (F. P. C.) 2676
7 Natural Gas Company gas sold or delivered by companies for year ending June 30, 1938 (F. P. C.) 2677
8 Natural Gas Company report of purchased gas and cost, 1934 to 1938, inc. (F. P. C.) 2679
9 Natural Gas Company consolidated operating analysis of gas purchases and sales, 1934 to 1938, inc. (F. P. C.) 2681
10 Natural Gas Company Sales and Revenue, 1934 to 1938, inc. (F. P. C.) 2683
11 Natural Gas Company Sales Agreements on file with Federal Power Commission (F. P. C.) 2685

Vol. I, pp. 1 to 646; Vol. II, pp. 647 to 1310; Vol. III, pp. 1311 to 1976; Vol. IV, pp. 1977 to 2672; Vol. V, pp. 2673 to 3031; Vol. VI, pp. 3033 to 3417; Vol. VII, pp. 3419 to 3902; Vol. VIII, pp. 3903 to 4023.

No.	Exhibits.	
14	Map showing delivery points and Natural Gas Transmission Lines (F. P. C.)	2687
15	Natural Gas Company and Texoma Company Earnings Statements, Calendar Years to December 31, 1938 (I. C. C.)	2689
28	Natural Gas Reserves — Texas Panhandle (Defts.)	2756
36	Natural Gas Reserves — Texas Panhandle (Defts.)	2757
41	Natural Gas Reserves — Texas Panhandle (Defts.)	2759
43	Explanation of Reserve Calculations (Defts.)	2760
44	Details of Reserve Estimate Marginal Gas Acreage—Texas Panhandle Field (Defts.)	2767
53	Errata—Exhibit No. 15 (I. C. C.)	2771
54	Natural Gas Company and Texoma Company Balance Sheets, December 31, 1934 to 1938, inc. (I. C. C.)	2771
78	Picture showing assembly of two 18-inch gas lines upon a suspension bridge across Big Blue River in Moore County, Texas (Defts.)	2783
79	Two photographs: Canadian River crossing in Hutchinson County, Texas, and typical manifold for submerged river crossing (Defts.)	2785
84	Map showing distances of Panhandle, Michigan and Illinois Fields from Chicago (Defts.)	2787
85	Photographs of Scenes at Pipeline Break near Sheffield, Illinois (Defts.)	2789
86	Statement of Open Flows and Rock Pressures on Date Wells were abandoned. Eldorado & Augusta Fields—Butler County, Kansas (Defts.)	2801

Vol. I, pp. 1 to 646; Vol. II, pp. 647 to 1310; Vol. III, pp. 1311 to 1976; Vol. IV, pp. 1977 to 2672; Vol. V, pp. 2673 to 3031; Vol. VI, pp. 3033 to 3417; Vol. VII, pp. 3419 to 3902; Vol. VIII, pp. 3903 to 4083.

No. Exhibits.

92 Picture of Compressor Station No. 1 (Defts.)...2803
114 Regulatory Expense (Defts.).....2805
116 General Expense, Taxes, New Business Expense (Defts.) 2806
117 Summary of Additional Capital Expenditures and Operation and Maintenance (Defts.).....2819
122 Salvage Value as of December 31, 1954 (Defts.).2841
Non-Salvageable Property not listed in Exhibit 122 1143
123 Picture Showing Interior of Fritch Station and 12 Engines (Defts.) 2907
124 Errata Sheets for Exhibit 122 (Defts.).....2911
125 Volumes I and II of Valuation (Portions of) (Defts.) 2922
129 Personnel Data—Key men in Chicago Office, etc. (Defts.) 2927
130 Cost of Attaching Business (Defts.).....2943
131 Market Value of Leases (Summary Sheet) (Defts.).....2947
132 Quotations and Yields of U. S. Treasury Notes and Bonds at Close of Market on August 15, 1939 (Defts.) 2951
133 Average Yield obtainable from Investments in U. S. Notes and Bonds (Defts.).....2953
134 Explanation of Method Used in Determining Reserves as of 8/1/31, on Acreage owned by Texoma 1/1/39 (Defts.).....2955
136 Earnings Statements for Calendar Years 1932 to 1938, inclusive (Defts.).....2958
137 Balance Sheets and Statements of Plant and Equipment December 31, 1931 to December 31, 1938, inclusive (Defts.).....2989

No.	Exhibits.	
138	Statement of Operating Revenue and Expenses, etc. (Defts.)	3003
140	Earnings Statement covering entire life of Project (Defts.)	3021
141	Earnings Statement based on Book Cost as of January 1, 1939 (Defts.)	3025
142	Earnings Statement based on Reproduction Cost new less existing depreciation as of June 1, 1939 (Defts.)	3029
145	Reconciliation of Statement Included in Exhibits 136 and 15 (Defts.)	3033
146	Texoma Natural Gas Company Summary of Market Value of Leases (Defts.)	3069
147	Natural Gas Co. and Texoma Co. Data concerning Rate of Return, etc. (Defts.)	3071
148	Natural Gas Co. and Texoma Co. Data concerning Rate of Return—Year 1938 (Defts.)	3079
149	Estimated Earnings on Account of Increased Capacity and Delivery of Natural Gas when operating at Higher Pipe Stresses (Defts.)	3105
150	Natural Gas Co. and Texoma Co. Data concerning Rate of Return (Defts.)	3106
151	Photostat of Investment Treatises (Defts.)	3123
152	Natural Gas Co. and Texoma Company Data concerning Rate of Return (Defts.)	3141
154	Article by Paul Ryan, "The Natural Gas Industry an Expanding Service" (F. P. C.)	3305
155	Facing Sheet and Pages 4 and 5 from 1st amendment to Registration Statement of Public Service Co. of Colorado, filed with S. E. C. 12/10/38 (F. P. C.)	1880, 3314

Vol. I, pp. 1 to 646; Vol. II, pp. 647 to 1310; Vol. III, pp. 1311 to 1976; Vol. IV, pp. 1977 to 2672; Vol. V, pp. 2673 to 3031; Vol. VI, pp. 3033 to 3417; Vol. VII, pp. 3419 to 3902; Vol. VIII, pp. 3903 to 4023.

No. Exhibits.

156 Certified copy of Gallagher's Exhibits 2 and 2A covering estimate of Investment and Anticipated Average Annual Net Earnings relative Docket 21170 before Illinois Commerce Commission (I. C. C.) 3320

Exhibit 2—Estimate of Investment in Facilities for Production of Natural Gas in Texas, etc. 3321

Exhibit 2A—Revised page 1 of Exhibit 2...3333

157 Certified copy of Gallagher's testimony before Illinois Commerce Commission in connection with Exhibit 2 of Commerce Commission and covering Pages 12 to 99, inc. of record in case No. 21170 (I. C. C.).....3335

158 Facing Sheet and Page 62 from 1st amendment to Registration Statement of Public Service Co. of Colorado filed with S. E. C. 12/10/38 (F. P. C.) 3374

159 Facing Sheet and Pages 5 and 6 from Registration Statement of Public Service Company of Colorado filed with S. E. C. 8/30/39 (F. P. C.)...3379

160 Facing Sheet and Page 57 of Registration Statement of Public Service Company of Colorado filed with S. E. C. 8/30/39 (F. P. C.).....3385

161 Release No. 1667 of S. E. C. under Holding Company Act containing findings and opinion re Northern Natural Gas Co. (F. P. C.).....1884, 3390

162 Letter of Ralph E. Davis, Inc. to Northern Natural Gas Co. dated 6/1/39 re Natural Gas Reserves (F. P. C.).....1885, 3401

Vol. I, pp. 1 to 646; Vol. II, pp. 647 to 1310; Vol. III, pp. 1311 to 1976; Vol. IV, pp. 1977 to 2672; Vol. V, pp. 2673 to 3031; Vol. VI, pp. 3032 to 3417; Vol. VII, pp. 3419 to 3902; Vol. VIII, pp. 3903 to 4022.

No.	Exhibits.
163	Pages 8, 9, 10 from Registration Statement filed with S. E. C. by Panhandle Eastern Pipeline Co. covering Ralph E. Davis Production Property and Gas Reserves (I. C. C.) 3408
167	Exhibit 49 in case of Chgo. District Pipeline Co. v. Lindheimer, et al., comparing present market price of issuance of Natural Gas Bonds (F. P. C.) 3413
168	Poor's Public Utility Volume 1939—Pages 164-167, inclusive (F. P. C.) 3419
169	Pages a55 to a61, inclusive of Moody's Manual of Investments 1939 (F. P. C.) 3428
170	Page 250 from American Gas Association Monthly, August, 1939, "Expanding Markets for Gas Industry Make Investments Sound," by P. S. Young (F. P. C.) 3458
171	Pages 19-20-37 from "Gas"—July, 1939, article by Percy S. Young entitled "The Investment Attributes of Gas Utility Securities" (F. P. C.) 3460
172	Pages 251-255 of American Gas Association Monthly issue of July-August, 1939, article, "A Banker Analyzes Natural Gas Industry Investment Values," by Frank R. Denton (F. P. C.) ..3468
173	Pages 37, 38, 43 of "Gas," May, 1939, issue, article, "A Stock Broker Analyzes the Natural Gas Industry," by John Nickerson III (F. P. C.) ...3471
174	Pages 56-61, incl. from 1939 Autumn issue of "The Index" article, "The Gas Industry" (F. P. C.) 3477

No.	Exhibits.	
176	Pages 253-255, incl. from issue of July-August, 1939, of American Gas Association Monthly article, "The Fifth Big Job," by Charles R. Bellamy (F. P. C.)	3486
178	Pages 24-33 from January, 1939, issue of "Gas" article, "The Natural Gas Industry Provides Opportunities for Investment," by James S. Carroll (F. P. C.)	3492
179	Statistical Bulletin No. 37 of American Gas Association dated October, 1939, entitled "Annual Statistics of the Natural Gas Industry in 1938" (F. P. C.)	3496
180	Trends of Interest Rates and Bond Yields (I. C. C.)	3523
181	Summaries of Recent Financing by Natural Gas Systems (I. C. C.)	3535
182	Computations in Regard to the Sinking Fund Method of Amortization and Rate of Return on Net Investment (I. C. C.)	3553
183	Money Market Factors (I. C. C.)	3559
184	Exhibit 20, entitled "Details of Items of Expense in Operation of a Single Pipe Line from Texas to Joliet, Illinois and certain misc. data," in Peoples Case before Ill. Comm. Com. No. 21170 (I. C. C.)	3567
185	Rate of Return Study—Part I (F. P. C.)	3576
186	Rate of Return Study—Part II (F. P. C.)	3724
187	Comparative Statement of Combined Profit and Loss for 8 months ended August 31, 1939 and 1938 (I. C. C.)	3784

Vol. I, pp. 1 to 646; Vol. II, pp. 647 to 1310; Vol. III, pp. 1311 to 1976; Vol. IV, pp. 1977 to 2672; Vol. V, pp. 2673 to 3031; Vol. VI, pp. 3033 to 3417; Vol. VII, pp. 3419 to 3902; Vol. VIII, pp. 3903 to 4023.

No.	Exhibits.	
188	Proforma Comparative Balance Sheets Annually at Dec. 31 from 1939 to 1954 and after liquidation (I. C. C.)	3785
191	Revision of Chart 8 and Supporting Schedule No. 12 in Exhibit 185 (F. P. C.)	3841
192	Revision of Chart 10 and Supporting Schedule No. 14 in Exhibit 185 (F. P. C.)	3849
193	Revision of Chart 11 and Supporting Schedule No. 15 in Exhibit 185 (F. P. C.)	3855
195	Revision of Chart No. 12 of Exhibit 185 (Defts.)	3859
196	Revision of Chart No. 14 of Exhibit 185 (Defts.)	3863
197	Study of Yields at Market Prices of Electric Operating Utility Preferred Stock and number of times dividend and prior requirements are earned, Based on Market Prices for week ended Nov. 17, 1939—Income for latest 12 months (F. P. C.)	3867
198	Earnings—Price Ratios of Electric Operating Utility Common Stocks and Per Cent of Gross Income available for common stocks, market prices for week ended Nov. 17, 1939, annual income from latest quarterly reports (F. P. C.)	3869
201	Photostat of Voucher 55810 (6/21/38) $5105.15 to Ralph E. Davis, Inc. (F. P. C.)	3871
202	Data on Sales, Revenue and Customers—Peoples Gas Lt. and Coke Co. (Defts.)	3877
203	Residential Electric Service in United States (Defts.)	3885
204	Commonwealth Edison Co. (Customers, Consumption, Revenue, and Rate) (Defts.)	3885

Vol. I, pp. 1 to 646; Vol. II, pp. 647 to 1310; Vol. III, pp. 1311 to 1976; Vol. IV, pp. 1977 to 2672; Vol. V, pp. 2673 to 3031; Vol. VI, pp. 3033 to 3417; Vol. VII, pp. 3419 to 3902; Vol. VIII, pp. 3903 to 4023.

No.	Exhibits.	
205	All Mortgage Bonds of Domestic Electric and Gas Utility Companies traded on New York Curb September 15, 1939 (Defts.)	3886
206	All Preferred Stocks of Domestic Electric and Gas Operating Utilities paying full dividends Listed N. Y. Curb (Sept. 15, 1939, Prices) (Defts.)	3888
207	Gross Operating Revenue and Total Net Available for Fixed Charges After Depreciation of the Gas Departments of the Three Utilities Distributing Gas in the Chicago Area (Defts.)	3891
208	Gas, Electric and Telephone Utility Companies serving City of Chicago (Defts.)	3893
209	Bonds, Debentures and Notes of Natural Gas Companies holdings by public (Defts.)	3895
210	Revision of Page One in Exhibit No. 141 (Defts.)	3901
211	Revision of Page One in Exhibit No. 142 (Defts.)	3902

Motion for Interim Order reducing rates, filed November 7, 1939 3903

Defendants' Pleas to Jurisdiction and Reply to motion for Interim Order filed December 18, 1939 3914

Conditional Answer to motion for Interim Order, etc., filed Dec. 18, 1939 3920

Memorandum Opinion, filed July 23, 1940 3925

Order reducing rates, entered July 23, 1940 3942

Motion for stay of order of July 23, 1940, filed August 8, 1940 3947

Objections of Illinois Commerce Commission to motion for stay of order, filed August 9, 1940 3958

Order granting in part and denying in part motion for stay of order of July 23, 1940, entered August 8, 1940 3960
Application for Rehearing, filed August 16, 1940 3961
Order denying Rehearing, entered September 6, 1940 3993
Certificate to Record 3994

PAPERS FILED IN U. S. COURT OF APPEALS.

Petition for Review, filed September 11, 1940 3997
Statement of Points 4009
Stipulation as to Printing 4020
Supplemental Stipulation as to Printing 4022

I

Order staying order of Commission 4025
Opinion, Evans, J 4026
Judgment 4041
Clerk's certificate 4042
Orders allowing certiorari 4043

Vol. I, pp. 1 to 646; Vol. II, pp. 647 to 1310; Vol. III, pp. 1311 to 1976; Vol. IV, pp. 1977 to 2672; Vol. V, pp. 2673 to 3031; Vol. VI, pp. 3032 to 3417; Vol. VII, pp. 3419 to 3902; Vd. VIII, pp. 3903 to 4023.

PROCEEDINGS.

Examiner Durrance: The hearing will be convened.

This hearing is in the matter of Illinois Commerce Commission, complainant, *vs.* Natural Gas Pipeline Company of America and Texoma Natural Gas Company, defendants; designated on Commission's docket as No. G-109; also In the Matter of Natural Gas Pipeline Company of America and Texoma Natural Gas Company, designated on Commission's docket as No. G-112.

The purpose of this hearing is to develop facts in order that the Commission might determine whether any transportation or sale of natural gas, subject to the jurisdiction of the Commission, any rates, charges or classifications demanded, observed, charged or collected, or any rules, regulations, practices, or contracts affecting such rates, charges, or classifications are unjust, unreasonable, unduly discriminatory, or preferential.

On September 23, 1938, the Illinois Commerce Commission of the State of Illinois filed its petition with the Federal Power Commission, which reads as follows: Filed Sept. 23, 1938.

"To The Federal Power Commission:

"Your petitioner, the Illinois Commerce Commission, respectfully represents as follows:

"1. That the Illinois Commerce Commission is a Commission organized and existing under the Public Utilities Act of the State of Illinois, and a State Commission within the meaning of Section 13 of the Natural Gas Act of 1938, and with its principal office in the city of Springfield, Illinois.

"2. That the Natural Gas Pipeline Company of America (hereinafter called Natural Gas Company) is a corporation organized and existing under the laws of the State of Delaware, with its principal office at 20 North Wacker Drive, City of Chicago, State of Illinois, owning a 24-inch pipeline extending from Gray, in the State of Oklahoma, to a point southwest of the City of Joliet, in the State of Illinois, and is a natural gas company engaged in the transportation of natural gas in interstate commerce, and the sale in interstate commerce of such gas for re-sale, within the meaning of Section 2(6) of the Natural Gas Act.

"3. That Texoma Natural Gas Company (hereinafter called Texoma) is a corporation organized and existing under the laws of the State of Delaware, with its principal

office at 20 North Wacker Drive, City of Chicago, State of Illinois, owning and operating gas wells, field gathering lines, compressor stations and a gasoline extraction plant in the State of Texas, and a 24-inch main pipeline which extends from Fritch, in the State of Texas, to Gray, in the State of Oklahoma, and is a natural gas company within the meaning of the Natural Gas Act, engaged in the transportation of natural gas in interstate commerce, and the sale in interstate commerce of such gas for re-sale.

"4. That Natural Gas Company has outstanding 1,500,000 capital shares of which 399,435,465 shares (26.629%) are owned by Natural Gas Investment Company, an Illinois Corporation whose stock is owned by the Peoples Gas Light and Coke Company (79.54%), Public Service Company of Northern Illinois (16.185%) and Commonwealth Subsidiary Corporation (4.275%); that the balance of 73.371% of the shares of Natural Gas Company is owned in various percentages by Standard Oil Company of New Jersey, Southwestern Development Company, Cities Service Company, the Texas Company and Columbian Carbon Company; that 26.629% of the capital stock of Texoma is likewise owned by Natural Gas Investment Company and the balance of 73.371% by the other companies owning the stock of Natural Gas Company, with the exception of Standard Oil Company of New Jersey; that the owners of the common stock of Natural Gas Company and Texoma provided the funds for the purchase and construction of the properties in substantially the percentages represented by their ownership of the stocks of those companies.

"5. That natural gas, gathered in Texas and transported to Gray, Oklahoma, by Texoma, is transported through the pipeline of Natural Gas Company to a point southwest of the City of Joliet, in the State of Illinois, where it is delivered to the mains of Chicago District Pipeline Company, an Illinois corporation (hereinafter called Chicago District), a corporation organized and existing under the laws of the State of Illinois; that Chicago District is engaged as a public utility in the State of Illinois, in the business of conveying and transporting natural gas and selling it at wholesale to the Peoples Gas Light and Coke Company, Public Service Company of Northern Illinois, and Western United Gas and Electric Company, which latter companies are also public utilities engaged in the distribution of gas at retail to consumers in the State of Illinois.

"6. That all of the stock of Chicago District is owned by the Natural Gas Investment Company.

"7. That more than 92% of the total gas sold by Natural Gas Company is sold in the State of Illinois, and that substantially 90% of it is sold to Chicago District; that Chicago District and other utilities in Illinois buy such gas according to the terms of a series of contracts which were filed on August 22, 1938, with the Federal Power Commission by Natural Gas Company.

"8. That Chicago District sells substantially all of the gas which it purchases from Natural Gas Company to the Peoples Gas Light and Coke Company, Public Service Company of Northern Illinois, and Western United Gas and Electric Company, at rates filed with this Commission, which are based substantially upon the price paid by Chicago District to the Natural Gas Company; that the three above distributing companies have severally obligated themselves, in the event of default by Chicago District, to pay to Natural Gas Company, during the term of the principal contract under which Chicago District buys from Natural Gas Company, their respective proportions, as fixed in the contract, of Chicago District's obligation to Natural Gas Company.

"9. That the Peoples Gas Light and Coke Company renders gas service to over 800,000 domestic and other users of gas in the City of Chicago; that the rates charged by Peoples Gas Light and Coke Company in the City of Chicago are dependent in large measure, upon prices which it pays to Chicago District for natural gas, which price is in turn determined by the price paid by Chicago District to Natural Gas Company; that the Peoples Gas Light and Coke Company in June, 1936, filed with this Commission an application for an increase in its rates amounting to approximately $3,000,000 annually; that on May 21, 1937, this Commission entered a final order denying the application of Peoples Gas Light and Coke Company for the rate increase; that on February 5, 1938, a permanent injunction was entered by the Circuit Court of Cook County, against the enforcement of the Commission's order; that the appeal of the Commission from the decree of said Circuit Court granting a permanent injunction is pending in the October Term of the Supreme Court of Illinois.

"10. That this Commission on November 19, 1936, entered an order directing Chicago District Company to show cause why its wholesale rates for gas should not be re-

duced, and that case was pending before the Commission at the time of the passage of the Natural Gas Act.

"11. That the sales of natural gas by Natural Gas Company to Chicago District Company since the beginning of regular operation by that company (January 1, 1932) were as follows:

1932	$ 5,609,274.40.
1933	5,736,842.95.
1934	8,305,978.17.
1935	10,485,556.53.
1936	12,562,288.15.
1937	13,215,053.13.

"12. That the sales by Chicago District Company to the Peoples Gas Light and Coke Company for the same period were as follows:

1932	$ 5,707,963.91.
1933	5,731,112.74.
1934	7,846,057.68.
1935	9,397,900.13.
1936	10,894,941.98.
1937	10,978,093.49.

"13. That the operating arrangements between Natural Gas Company and Texoma are such that they may properly be considered as being operated as a single enterprise; that the total gross investment in property (i. e. gross expenditure to date with no deduction for property retired except for sales of property and any salvage realized) for Natural Gas Company and Texoma up to December 31, 1937, was $65,247,635.70.

"14. That the net earnings of Natural Gas Company and Texoma before amortization, depreciation, depletion or retirements, since the beginning of regular operations were as follows:

1932	$ 3,641,658.38.
1933	4,066,914.58.
1934	6,167,298.17.
1935	8,451,656.75.
1936	10,279,625.44.
1937	10,795,327.93.

"15. That the above earnings after an annual amortization allowance, based on an estimated life of twenty years for the property and found to be reasonable by this Com-

mission in its Order of June 16, 1933, in Docket No. 21261, represent for the period of operation up to December 31, 1937, a return of approximately 8.2% upon the average gross investment in property plus an allowance of $1,000,000 substantially as found to be reasonable by this Commission in its order of June 16, 1933, for working capital; that the earnings computed on the same basis were 13.40% for the year 1937.

"16. That in the proceeding referred to in the next preceding paragraph the companies contended for amortization on a fifteen year basis; that the earnings, after amortization of approximately $3,000,000 per year on a fifteen year basis, corresponding to the $1,994,266 on a twenty year basis, were for the period 1932-1937 approximately 6.5% upon the average gross investment plus working capital; and that the earnings on the same basis for the year 1937 were approximately 11.7%.

"17. That Natural Gas Company has outstanding $3,000,000 of common stock on which it paid, up to December 31, 1937, the following dividends:

1936	$2,775,000.00.
1937	4,125,000.00.

"18. That the rates and charges for natural gas charged by Natural Gas Company to Chicago District and other public utilities in the State of Illinois are unjust and unreasonable and the fixing of fair, just and reasonable rates will materially aid this Commission in fixing fair, just and reasonable rates for gas sold to ultimate consumers in Illinois.

"Wherefore, your petitioners request:

"1. That a citation order be immediately entered by this Honorable Commission directing the Natural Gas Company and Texoma, to appear and show cause why the rates charged Chicago District and other utilities in Illinois, should not be reduced.

"2. That an order be entered setting fair, reasonable and just rates for natural gas sold by Natural Gas Company to Chicago District and other utilities in Illinois.

"Dated at Springfield, Illinois, this 21st day of September, A. D. 1938.

Illinois Commerce Commission,
By William W. Hart,
Secretary.

(Seal)

State of Illinois, }
County of Sangamon. } ss.

William W. Hart, being first duly sworn on oath, deposes and says that he is the Secretary and the duly authorized representative of the Illinois Commerce Commission to subscribe and verify the foregoing petition; that he has read the same and knows the contents thereof and that the matters and things therein contained are true to the best of his knowledge, information and belief.

William W. Hart.

Subscribed and Sworn to before me this 21st day of September, A. D. 1938.

Rena Tomlins,
Notary Public."

Entered Oct. 14, 1938.

Thereafter, on October 14, 1938, the Federal Power Commission initiated its own investigation as to conditions and circumstances alleged to prevail in the foregoing petition and, with reference thereto, adopted the following order:

"Order Instituting Investigation.

"It appearing to the Commission that:

"(a) The Natural Gas Pipeline Company of America, a corporation, organized and existing under the laws of the State of Delaware, owns and operates a main transmission natural gas pipe line extending from Gray, Oklahoma, through the states of Oklahoma, Kansas, Nebraska, Iowa and Illinois, to a point southwest of Joliet, Illinois;

"(b) The Texoma Natural Gas Company, a corporation organized and existing under the laws of the state of Delaware, owns and operates gas wells, gathering systems, and a main transmission natural gas pipe line extending from Fritch, Texas, to Gray, Oklahoma;

"(c) The Natural Gas Pipeline Company of America and the Texoma Natural Gas Company are under substantially similar common control and ownership, and are in all substantial respects operated as a single enterprise for the production, gathering, transportation and sale of natural gas;

"(d) The Natural Gas Pipeline Company of America and the Texoma Natural Gas Company are engaged in the

transportation of natural gas in interstate commerce and the sale in interstate commerce of natural gas for resale for ultimate public consumption for domestic, commercial, industrial, or other uses, and are therefore natural-gas companies within the meaning of the Natural Gas Act;

"(e) Pursuant to Section 4(c) of the Natural Gas Act and the Commission's Order No. 53, the Texoma Natural Gas Company, on August 22, 1938, filed with the Commission its contract and agreement covering the sale of natural gas to the Natural Gas Pipeline Company of America, and the Natural Gas Pipeline Company of America, on August 22, 1938, filed with the Commission its contracts and agreements covering the sale of natural gas to the Chicago District Pipeline Company, the Central Power Company, the Central States Electric Company, the United Gas Service Company, the Iowa Power & Light Company, the Cedar Rapids Gas Company, the Iowa-Nebraska Light & Power Company, the Ottumwa Gas Company, the Peoples Power Company, the Peoples Light Company, the Iowa City Light and Power Company, and the Cities Service Gas Company;

"(f) On September 23, 1938, the Illinois Commerce Commission, a State Commission within the meaning of the Natural Gas Act, filed with the Commission a petition, reciting, among other things, that natural gas produced, gathered and transported by the Texoma Natural Gas Company and the Natural Gas Pipeline Company of America is delivered and sold by the latter company to the Chicago District Pipeline Company, a corporation, organized and existing under the laws of the State of Illinois; that such gas is sold at wholesale by the Chicago District Pipeline Company to the Peoples Gas Light and Coke Company, the Public Service Company of Northern Illinois, and the Western United Gas and Electric Company, which are public utilities engaged in the local distribution of gas at retail to consumers in the State of Illinois; that more than 92 per cent of the total gas sold by the Natural Gas Pipeline Company is sold in Illinois and that substantially 90 per cent of such gas is sold to the Chicago District Pipeline Company; that the Chicago District Pipeline Company sells substantially all of the gas which it purchases from the Natural Gas Pipeline Company of America to the Peoples Gas Light and Coke Company, the Public Service Company of Northern Illinois, and the Western United Gas and Electric Company, at rates filed with the Illinois Commerce Commission, which are based

substantially upon the price paid by the Chicago District Pipeline Company to the Natural Gas Pipeline Company of America; that the Peoples Gas Light and Coke Company renders gas service to over 800,000 domestic and other users of gas in Chicago, and that the rates charged by said company in Chicago are dependent in large measure upon prices which it pays to Chicago District Pipeline Company for natural gas, which price is in turn determined by the price paid by Chicago District Pipeline Company to Natural Gas Pipeline Company of America;

"(g) The said petition of the Illinois Commerce Commission alleges that the rates and charges for natural gas charged by Natural Gas Pipeline Company of America to Chicago District Pipeline Company and other public utilities in the State of Illinois are unjust and unreasonable, and the fixing of fair, just and reasonable rates by this Commission will materially aid the Illinois Commerce Commission in fixing fair, just and reasonable rates for gas sold to ultimate consumers in Illinois.

"Wherefore, the Commission finds that:

"It is necessary and proper, in the public interest, and to aid in the enforcement of the provisions of the Natural Gas Act, that an investigation be instituted by the Commission, on its own motion, into and concerning all rates, charges, classifications, rules, regulations, practices or contracts of the Natural Gas Pipeline Company of America and the Texoma Natural Gas Company;

"The Commission, on its own motion, orders that:

"An investigation of the Natural Gas Pipeline Company of America and the Texoma Natural Gas Company be and is hereby instituted, for the purpose of enabling the Commission: (1) To determine, with respect to each of said companies, whether in connection with any transportation or sale of natural gas subject to the jurisdiction of the Commission, any rates, charges, or classifications demanded, observed, charged or collected, or any rules, regulations, practices, or contracts affecting such rates, charges, or classifications, are unjust, unreasonable, unduly discriminatory, or preferential; and (2) if the Commission shall find that any such rates, charges, classifications, rules, regulations, practices, or contracts are unjust, unreasonable, unduly discriminatory, or preferential, to determine and fix by appropriate order or orders just, reasonable and non-discriminatory rates, charges, classi-

fications, rules, regulations, practices or contracts to be thereafter observed and in force.

By the Commission.

Leon M. Fuquay,
Secretary."

Filed Nov. 16, 1938.

Subsequent thereto, on November 16, 1938, the defendants filed in reply its answer to the petition, which reads as follows:

"Natural Gas Pipeline Company of America, a corporation, hereinafter called defendant Pipeline Company when mentioned separately, and Texoma Natural Gas Company, a corporation, hereinafter called defendant Gas Company when mentioned separately, the two hereinafter called defendants when mentioned together, without waiving their plea set forth in paragraph numbered 7 hereof, but still insisting on same, and subject to the ruling of this Honorable Commission and of the courts on such plea, for their reply and answer to the petition of Illinois Commerce Commission, hereinafter called complainant, say:

"1. They admit the allegations contained in paragraphs numbered 1, 2, 3, 4 (if a decimal point be substituted for the second comma in line two thereof), the first seven lines of paragraph numbered 5, and all of paragraphs numbered 10, 11 and 17. In connection with paragraph numbered 17 they represent that while the outstanding stock was originally set up on the books at $3,000,000, its value now is greatly in excess of that amount. They point out, however, that the figures contained in paragraph numbered 17 are immaterial. They admit the allegations contained in paragraph numbered 7 thereof, with the qualification that the figures '92%' and '90%' vary from time to time, though they are approximately correct. They have no accurate knowledge except from hearsay concerning the facts alleged in the last seven lines of paragraph numbered 5 and paragraphs numbered 6, 8, 9, and 12 thereof, for which reason they neither admit nor deny such allegations.

"2. They admit that the figures set out in paragraph numbered 13 of said petition are substantially correct. In this connection, however, defendants represent that the expenditures heretofore made by defendants do not

represent all of the investments heretofore made on their behalf or the investments which they will find it necessary to make during the remaining life of their enterprise. In addition to these expenditures the stockholders of defendants during the preliminary organization and construction period expended large sums of money and performed important services of substantial value, which, though not capitalized by defendants, represent substantial additional investments, which defendants are entitled to capitalize. As a result of changing physical conditions, defendants have been obliged, in the exercise of reasonable prudence and good judgment, to increase their original investment from time to time. They are now making substantial additions to their plant investment; and during the remaining life of their project they will be required from time to time to make other very substantial additions thereto, in order to produce, transport and market the natural gas from their reserves in the State of Texas.

"3. They admit that the figures set out in paragraph numbered 14 of said petition are substantially correct. In this connection, however, they represent that their net earnings during the year 1937 probably represent the highest level of earnings during the entire life of their project. During the year 1938 their net earnings have decreased by substantial amounts as compared with the earnings during the corresponding period of 1937 or 1936. The changing physical conditions obtaining in the field or reservoir in the State of Texas where their leases are situated and the deterioration from aging and wear and tear on their physical properties during the remaining years through which their enterprise will continue in operation will inevitably increase the expenses and cost to defendants of producing, transporting and marketing their commodity. It necessarily follows, therefore, that during such remaining years the net earnings of defendants from the operation of their business will be substantially and progressively reduced.

"4. They deny each allegation contained in paragraphs numbered 15 and 16 of said petition.

"5. They deny the allegation in paragraph numbered 18 of said petition that the rates or charges for natural gas charged by defendant Pipeline Company to Chicago District Pipeline Company and other public util-

ities in the State of Illinois are unjust and unreasonable; and they deny the allegations contained in the same paragraph to the effect that the fixing of other and different rates or charges for such commodity will materially aid the complainant, Illinois Commerce Commission, in fixing fair, just and reasonable rates for gas sold to ultimate consumers in the State of Illinois.

"6. Defendants deny the right of complainant to an order by this Honorable Commission directing defendants to appear and show cause why the prices charged Chicago District Pipeline Company and other utilities in Illinois should not be reduced; and in this connection they point out that this Honorable Commission is without jurisdiction, power or authority to promulgate or enforce against these defendants or either of them any order directing them to appear and show cause why their existing prices, fixed by private contracts on file with this Honorable Commission, should not be reduced.

"7. Defendants deny and challenge any jurisdiction, power or authority of this Honorable Commission to enter any order attempting to change, modify or set aside any charge or price at which defendant Pipeline Company is selling natural gas to Chicago District Pipeline Company or to other utilities in the State of Illinois or elsewhere, or to substitute and prescribe any different charges or prices for which defendant Pipeline Company shall sell such commodity in the State of Illinois or elsewhere, on the ground that defendants, in legal effect and in fact, constitute a single enterprise engaged in the business of owning natural gas leases or reserves in the State of Texas, developing such reserves through the drilling and equipping of wells thereon, producing their natural gas therefrom, transporting same through their own pipelines and facilities to points in the States of Kansas, Nebraska, Iowa and Illinois, and selling such commodity at wholesale to selected distributors and industrial consumers under private contracts. Such enterprise or business is of a strictly private character and is not affected with a public interest in the sense that the Congress would have jurisdiction, power or authority to enact legislation purporting to authorize this Honorable Commission to regulate the charges or prices for which such commodity is sold. The Natural Gas Act of 1938 enacted by the Congress, in so far as such act

purports to confer on this Honorable Commission any jurisdiction, power or authority to regulate, change, modify or set aside the charges or prices at which defendant Pipeline Company is selling natural gas at wholesale to distributors or industrial consumers, or to authorize it to set up and prescribe different charges or prices for such commodity, and any rules, regulations or orders promulgated by this Honorable Commission with a view of attempting to exercise any such purported jurisdiction, power or authority, are, therefore, null and void and unenforcible as against these defendants because the inevitable operation and effect thereof will deprive defendants of their property and liberty of contract without due process of law, in violation of the Fifth Amendment to the Constitution of the United States.

Natural Gas Pipeline Company of America
Texoma Natural Gas Company
By J. J. Hedrick
20 North Wacker Drive, Chicago, Ill.
Geo. P. Garver
20 North Wacker Drive, Chicago, Ill.
S. A. L. Morgan
20 North Wacker Drive, Chicago, Ill.
Their Attorneys.

Morgan, Culton, Morgan & Britain
of Amarillo, Texas.
Of Counsel.

"State of Illinois, }
County of Cook. }

"Floyd C. Brown, being first duly sworn, says that he is Vice President and General Manager of Natural Gas Pipeline Company of America and Texoma Natural Gas Company, defendants herein; that he has read the pleas, admissions, denials and averments in the foregoing answer and that the same are true as he verily believes.

Floyd C. Brown.

"Sworn to before me and subscribed in my presence this 14th day of November, A. D. 1938.

Esther M. Wilson,
Notary Public,
Cook County, Illinois.

"Certificate of Service of Defendants' Answer.

"I hereby certify that I have this day served the foregoing document upon all parties of record in this proceeding by mailing a copy thereof, properly addressed, to Illinois Commerce Commission at Springfield, Illinois.

"Dated at Chicago, Illinois, this 14th day of November, 1938.

J. J. Hedrick,
Of Counsel for Natural Gas Pipeline Company of America and Texoma Natural Gas Company."

On April 14, 1939, the Commission adopted an order fixing the date of hearing and consolidated the investigation instigated by it with the complaint filed by the Illinois Commerce Commission, which reads as follows: Entered Apr. 14, 1939.

"Order Fixing Date of Hearing.

"It appearing to the Commission that:

"(a) In Docket No. G-109, on September 23, 1938, the Illinois Commerce Commission, a State Commission within the meaning of the Natural Gas Act, filed with the Commission a complaint alleging that the rates and charges for natural gas charged by the Natural Gas Pipeline Company of America to Chicago District Pipeline Company and other public utilities in the State of Illinois are unjust and unreasonable, and the fixing of fair, just and reasonable rates by this Commission will materially aid the Illinois Commerce Commission in fixing fair, just and reasonable rates for gas sold to ultimate consumers in Illinois; in their answer to said complaint, filed with the Commission on November 16, 1938, the Natural Gas Pipeline Company of America and the Texoma Natural Gas Company deny that the rates and charges for natural gas charged by the Natural Gas Pipeline Company of America to the Chicago District Pipeline Company and other public utilities in Illinois are unjust and unreasonable, and deny that the fixing of other and different rates or charges will materially aid the Illinois Commerce Commission in fixing fair, just and reasonable rates for gas sold to ultimate consumers in Illinois;

"(b) In Docket No. G-112, on October 14, 1938, the Commission on its own motion, instituted an investigation of the Natural Gas Pipeline Company of America and the Texoma Natural Gas Company (1) to determine, with respect to each of said companies, whether, in connection with any transportation or sale of natural gas subject to the jurisdiction of the Commission, any rates, charges, or classification demanded, observed, charged or collected, or any rules, regulations, practices, or contracts affecting such rates, charges, or classifications, are unjust, unreasonable, unduly discriminatory, or preferential; and (2) if the Commission shall find that any such rates, charges, classifications, rules, regulations, practices, or contracts are unjust, unreasonable, unduly discriminatory, or preferential, to determine and fix by appropriate order or orders just, reasonable and non-discriminatory rates, charges, classifications, rules, regulations, practices or contracts to be thereafter observed and in force;

"The Commission orders that:

"(A) Dockets Nos. G-109 and G-112 be and they are hereby consolidated for purposes of hearing thereon;

"(B) A public hearing in these proceedings be held commencing on May 8, 1939, at 10 o'clock a. m., in Room 425, New Post Office, Canal and Van Buren Streets, Chicago, Illinois.

By the Commission.

Leon M. Fuquay,
Secretary."

On April 18th, the Honorable Clyde L. Seavey, Acting Chairman of the Commission, designated Frank M. Durrance to preside at said hearing. This hearing is held in pursuance of the foregoing orders and designations.

At this time in the record, we will see if the appearances have been noted.

(Appearances noted as shown on title page.)

Examiner Durrance: The Examiner inquires of Commission's counsel if notice of this hearing and the purpose thereof has been served upon those who might be perceived to be interested therein.

Mr. May: They have, Mr. Examiner. Notices have been sent to the state commissions, governors, and other interested parties.

Examiner Durrance: The purpose of this hearing having been clearly stated, the Examiner, without, in any manner, suggesting delineation or limitation of the proof to be offered by the applicant, suggests that the record be completely developed to show:

1. A complete description of the properties owned by the defendants and costs of all natural gas producing lands owned or controlled by either company, segregated by fields and between operative and non-operative acreage.

2. The volume of natural gas produced by each company from each field and the average rock pressures reported at the end of each year since January 1, 1934.

3. The volume of natural gas purchased from each source by each company and the amounts paid for same by years since January 1, 1934.

4. The volume of natural gas sold by each company, segregated between gas sold for resale and gas sold to industrials, by years since January 1, 1934.

5. A detailed analysis of all operating expenses of each company, including depreciation and depletion charges, by years since January 1, 1934. This showing will involve the determination of the reasonableness of each item, especially non-recurring or unusual expenditures, and whether or not charges to operating expenses have been made of items that properly belong in capital investment account or vice versa.

6. All operating revenues received by each company, segregated between classes, by years since January 1, 1934.

7. A compilation of the recorded investment in property of each company, segregated between major classes of property, such as production, transmission, etc., at the end of each year since January 1, 1934.

8. Factors bearing on determination of reasonable rate of return.

The procedure will be for the defense to first offer its direct testimony. That will be followed by cross-examination of defendants' witnesses by Illinois Commerce Commission's counsel, to be followed by cross-examination by the Federal Power Commission's counsel.

The next step will be for the Illinois Commerce Commission to offer such direct testimony as it may desire; their witnesses to be cross-examined by defendants' counsel.

The next step will be for the Federal Power Commis-

sion's counsel to offer such direct testimony as they may desire, which they may deem to be helpful to the Commission in reaching its final determination of the issues involved in this case.

We will now proceed to take the testimony.

Mr. Morgan: Mr. Examiner: In the first place, I desire to call the attention of the Examiner and the Commission to our plea denying and challenging any jurisdiction, power or authority of the Federal Power Commission to enter any order attempting to change, modify or set aside any charge or price at which respondent pipeline company is selling natural gas to Chicago District Pipeline Company or to other utilities in the State of Illinois or elsewhere, or to substitute and prescribe any different charges or prices for which respondent pipeline company shall sell such commodity, and invoking the due process clause of the Fifth Amendment to the Constitution of the United States, as set out in Paragraph 7 of our answer to the complaint of Illinois Commerce Commission in No. G-109. This appearance and all other appearances to be made by us in connection with this proceeding or the investigation instituted by the Commission under Docket G-112, which proceedings have been consolidated, are made and will be made under protest, without waiving said plea to the jurisdiction and without waiving our constitutional rights under the Fifth Amendment, and all that we shall do or say here or hereafter in these proceedings will be expressly subject to the final determinations of our rights under said plea. We are not insisting on the Commission's passing on the constitutional question raised, since we recognize that it is without authority to hold the Natural Gas Act, under which it is purporting to proceed in this cause, or any part of said Act unconstitutional, as the Commission itself has held in other recent proceedings; but it is our purpose to save the point and urge it, should this cause reach the courts on an appeal by either party.

We are here in response to a notice dated April 14, 1939, advising that a public hearing in the consolidated proceedings would be held on this date and at this place. We received in due course a letter from the Secretary of the Commission dated April 28, 1939, advising that, pursuant to the provisions of Section 50.63 of the Provisional Rules of Practice and Regulations under the Natural Gas Act, the respondent companies have been designated to open and close the hearing beginning on this date.

To say that we were surprised to receive this communication is to put it very mildly. We have no application pending before the Commission and are seeking no relief in either of the proceedings above referred to. We are here to meet a complaint of the Illinois Commerce Commission and any complaint that the Federal Power Commission shall see fit to urge as against us when it shall have completed its investigation. Naturally, we do not know at this time whether there will ever be a complaint lodged against us by the Federal Power Commission, for it has scarcely more than begun its investigation, if we are to judge by the time the Illinois Commerce Commission has occupied in covering a small part of the ground that the Federal Power Commission will doubtless see fit to cover before reaching any conclusion as to whether or not the proceedings shall go beyond the stage of an inquiry or investigation.

Beginning in December, 1937, auditors and other representatives of the Illinois Commerce Commission spent approximately fifteen months on the books and records of these companies. In all, twenty-three persons were engaged in this work for a total of 17,327 man hours. On the basis of a 40 hour week, it would have required one man 9½ years to do this work, or four men—the number from the Federal Power Commission now engaged in similar work—more than two years. The Illinois Commerce Commission did not go over the properties, but confined its investigation to the books and records in the Chicago office, and with the force now engaged in this work it will doubtless be several months at the earliest before the Federal Power Commission can complete its inquiry, unless it turns out that they are able to accomplish a great deal more per man hour than did the force of the Illinois Commerce Commission. Of course, we would not charge that the Illinois Commerce Commission did not work very diligently during that 17,327 man hours.

This litigation was started by the Illinois Commerce Commission, or perhaps I would be more accurate if I said by its counsel. If Mr. Booth is not ready, he certainly ought to be. This is his case, and he has certainly had time enough to search out any facts which he thinks would tend to sustain the charges he has made in his petition.

We are not ready. We have done a great deal of work among our records and in the matter of revaluing the properties belonging to these companies, which are located in the several States of Texas, Oklahoma, Kansas, Nebraska, Iowa

and Illinois. Some of these studies were completed down to the first of January, 1938, during the period that we were engaged in litigation with the Illinois Commerce Commission before that body itself. We have not brought these studies down to date for the reason that we did not know, and do not now know, when the Federal Power Commission would complete its investigation, and we did not wish to incur the enormous expense involved in bringing these engineering studies down to a later date until we could know the date which the Federal Power Commission would select as the date when its figures would be closed. To do so, and then have the revised figures become out of date, would mean that they would have to be again revised at further heavy costs. The Federal Power Commission knows, of course, that the force of men regularly employed by these companies have daily and hourly duties to perform. They have been employed because these companies have need of them in the ordinary operations of the companies. They of necessity have to continue with their duties or the pipeline would have to be shut down. It is therefore impractical for these companies to take a large number of their regular employees off the job and assign them to the sole task of meeting Mr. Booth's allegations. It takes time, and a lot of time, to prepare the defense of a case like this, even after we know against what we are required to defend.

Mr. Booth has attacked our charges and prices to our distributing customers in the State of Illinois.

Mr. May: Just a minute. The complaint in this case was filed by the Illinois Commerce Commission. I do not understand counsel's tactics in attacking counsel for the Illinois Commerce Commission. As far as the Commission understands, this complaint was filed by the Illinois Commerce Commission; and I think we would prefer that Mr. Morgan confine his remarks to the Illinois Commerce Commission.

Mr. Morgan: I think I know what I want to say, but I will explain to the Commission and to the Examiner that when I mention Mr. Booth I mean the Illinois Commerce Commission.

We have two customers in the State of Illinois: the Chicago District Pipeline Company and Peoples Power Company. We have seven contracts fixing seven separate prices or charges for natural gas with Chicago District Pipeline Company, and six different contracts fixing six different prices or charges with Peoples Power Company. We do not

know from Mr. Booth's complaint which contract or contracts, which charge or charges, he is attacking. He makes no specific charge against any price or contract, but is content to say that we are making more money than we ought to make. His pleading is wholly insufficient, even if he had offered proof to support it, to justify this Commission in holding that the charges or prices of these companies are unjust, unreasonable, unduly discriminatory or preferential; but even if his pleading were sufficient as a pleading, we are not required to come here with evidence to refute a mere pleading. It is the business of the moving party to bring evidence here, and when he brings it we have a constitutional right, of which the Commission could not deprive us if it desired to do so, and we do not think it desires to do so, to test, explain and refute such testimony if we can, and we can.

After the filing of the complaint by the Illinois Commerce Commission, the Federal Power Commission on its own motion instituted an investigation which, as the Examiner knows, covers a lot of territory. It is conducting this investigation, first, to determine with respect to each of the respondent companies whether in connection with any transportation or sale of natural gas subject to the jurisdiction of the Commission any rates, charges or classifications demanded, observed, charged or collected, or any rules, regulations, practices or contracts affecting such rates, charges or classifications, are unjust, unreasonable, unduly discriminatory or preferential; and, secondly, if it shall find that any of such are unjust, unreasonable, unduly discriminatory or preferential, to determine and fix by appropriate order or orders just, reasonable and nondiscriminatory rates, charges, classifications, rules, regulations, practices or contracts to be thereafter observed.

In addition to the two customers and thirteen contracts under which we are delivering gas in the State of Illinois, we have seven customers in the State of Iowa, with whom we have a total of thirty contracts involving thirty different charges or prices.

Examiner Durrance: Pardon me just a moment. Could not that all be developed in the record by witnesses?

Mr. Morgan: I want to make a statement to the Examiner, stating our position. That is exactly what I am trying to do. I am developing this in my statement.

Mr. May: Is this in lieu of evidence, Mr. Morgan?

Mr. Morgan: I am making a statement in which I am

trying to make clear to the Examiner and the Commission our position in this case.

Mr. May: Do you want to make it clear this is not your evidence in the case on the points involved in this proceeding?

Mr. Morgan: I don't think it is necessary to make that clear, Mr. May. I haven't been sworn and examined, and I am not trying to testify in this case at all.

One customer in the State of Nebraska, with whom we have six contracts fixing six different charges or prices; and two customers in Kansas, with each of which we have one contract, each fixing a charge or price for natural gas. In all, therefore, we have eleven customers with a total of fifty-one contracts performed in four different states. Does the Commission propose to have us defend each and all of these contracts? If so, against what shall we defend them? Are we to defend them against the charge that they are unjust? Or that they are unreasonable? Or that they are unduly discriminatory? Or that they are preferential? Or is it charged that some of them are unjust, some of them unreasonable, some of them unduly discriminatory, and some of them preferential? If so, which of them are unjust, which of them are unreasonable, which are unduly discriminatory, and which are preferential? We haven't the slightest idea, and neither does the Federal Power Commission, for it has scarcely started its investigation, and neither does the Illinois Commerce Commission, for it makes no pretensions to have gone beyond the books and records of the Chicago office and has covered only a small portion of the ground that it will have to cover before it can make out a prima facie case against either of these companies in an attack on any of the charges or prices for which they are selling natural gas.

Mr. May: I think this line of argument should be reserved until argument before the Commission, if oral argument takes place, or in Mr. Morgan's brief. I don't see how he can possibly summarize evidence in advance of the time that the evidence is presented through witnesses in this proceeding. I think that is what he is attempting to do.

Mr. Morgan: No, no.

Mr. May: I don't think it has any purpose here.

Mr. Morgan: My purpose, if the Examiner please, is to state the basis for the position we are taking in this case, which I will be ready to state at the conclusion of this statement. This is stating our position, and I am merely stating

the ground-work of our position, so the record will show that we are not here taking an arbitrary position; but we are here making our position clear to the Commission.

Examiner Durrance: In connection with this contract which you referred to, Mr. Morgan, it would be very helpful to the Commission if we might have those. The Commission is only seeking the truth and the facts under the circumstances.

Mr. Morgan: They are all filed with the Commission, every one of them.

There is nobody here this morning who is able to say which of these contracts we are required to defend, or against what charges we are to defend any one of them. So far as we know now, it is not any of our contracts or the prices or charges which we are expected to defend. Is it our classifications, or our rulings, our regulations, our practices, that we must take the burden of defending? Naturally, a business of the magnitude of that conducted by these companies must have many classifications, many rules, many regulations, and divers practices and policies. The Federal Power Commission is investigating all of them. It tells us practically at the beginning of the investigation that we shall start putting on proof, without telling us which, if any, of our fifty-one contracts or charges we are expected to defend, or which of our numerous classifications, rules, regulations and practices observed by us in the States of Texas, Oklahoma, Kansas, Nebraska, Iowa, and Illinois we are expected to defend. That it is wholly impracticable, indeed impossible, from our standpoint to assume any such burden is clear; and it is incomprehensible that the Commission would direct us to do so.

Our position in this litigation is that our rates, charges, contracts, classifications, rules, regulations and practices are all reasonable and proper, and we believe that when the Federal Power Commission has completed its inquiry, if it is searching for the facts, as we understand it is, and not merely for an answer, it will find that our claim on this point is supported by the facts, and it will direct that no further proceedings shall be had in this matter. But in any event, no burden rests upon these defendants in any of these proceedings. As already stated, we are asking nothing of the Commission. We have filed our contracts, and the charges and prices fixed thereby are prima facie reasonable, and this Commission is without authority or jurisdiction to disturb those prices and charges until

such time as, after full hearing, it shall determine that they are unjust, unreasonable, unduly discriminatory or preferential; and the same is true of our classifications, rules, regulations and practices. The burden of proof is upon the moving parties on all these issues, and we are required to take no steps to defend them until we are confronted, not with allegations, not with orders, not with directions, but with proof, which we have the right to test, to explain and to refute. Until we are so confronted we have no duty to proceed. We are not here attacking a rule of the Federal Power Commission. Perhaps when properly applied the rule here sought to be invoked is valid. If the parties were here contending with each other as to who has the right to open and close, it would be the duty of the Commission to designate which should have the opening and closing; but we are claiming no such right. We claim only the right to cross-examine the witnesses, whom the moving parties may bring into this proceeding, concerning their testimony and the documents which shall be offered in connection with their testimony, to test the testimony that is offered against us, to explain it, and to refute it. There is nothing on which we can proceed at this time. We are not ready. We have not had time to get ready since the Federal Power Commission started this investigation; but I do not want to be understood merely as being here asking for time for the commencement of these hearings. If there is evidence on which the parties on whom the burden rests desire to go forward, we have no objection to their proceeding, beginning now; but we want to make it perfectly clear, while at the same time expressing our great respect for the Federal Power Commission, that we are not going to take the burden of proof in this case, nor are we going to take the laboring oar in developing the testimony here. When the moving parties have rested their case, we shall proceed with our testimony as soon as we can get it in readiness to proceed, if we find that those on whom the burden of proof rests have discharged that burden of proof and it then appears that it is in order for us to offer proof to explain or refute the testimony they shall have offered. It may be that we shall then conclude that the testimony offered does not suffice to sustain the findings necessary as a predicate to any order adversely affecting our contracts, prices, charges, classifications, rules, regulations or practices, and that we shall move to dismiss and stand on the record made by those carrying the laboring oar.

In taking this position, Mr. Examiner, we do not wish to be understood as assuming any attitude of defiance toward the Federal Power Commission. We recognize the Commission's right, subject to the serious question as to whether the Natural Gas Act is valid, to conduct the investigation it has ordered; and we have cooperated in every way possible with its representatives who are engaged in this work. We have rented an office and provided tables and chairs for their convenience. We have permitted them to examine our books and records and have furnished them with the information they have requested. At this very time we are engaged, at great expense, in opening our ditches at intervals of ten miles, and exposing our pipelines, in order that the Commission's representatives may view them. We shall continue to cooperate with them in every way that the law contemplates. But we just haven't anything to litigate with or before it at this time. We are perfectly happy with our contracts our charges and prices our classifications, rules, regulations and practices, and, so far as we know, all of our customers are as happy as we are about them. Indeed with the exception of the Illinois Commerce Commission, represented by Mr. Booth, we know of no one who is unhappy about them. We recognize that this is going to be a long drawn-out and very expensive litigation. So far as we are concerned, no litigation is in order or need be had. The fact is, Mr. Examiner, that we find ourselves very much in the attitude of the darky down South who found himself the center of interest in a criminal proceeding. After he had become utterly bewildered by listening to the arguments pro and con on a motion to quash the indictment, a motion to quash the jury panel, a motion for change of venue, a motion for continuance, on none of which the lawyers could agree and about which the court seemed bewildered, the darky turned to the presiding judge and said: "Mr. Jedge, it will be all right with me if ye just drap dis case!"

Examiner Durrance: Of course, counsel for the defense recognizes the fact that this is a consolidated hearing; consolidated by virtue of authority provided for in Rule 50.63 of the Commisison's Provisional Rules of Practice and Regulations under the Natural Gas Act.

Of course, the Examiner proceeds upon the theory that the rule vests the Commission with the authority which it has exercised in consolidating the hearing. That rule further provides that the Commission or the

Commission's representative, may designate the mode of procedure of developing the record. The Commission in this case has seen fit to designate that the defendants proceed to put on their testimony.

Now, in connection with your statement, as I understand it, if I have the picture clear in my mind, you are not prepared to put on any testimony at this time?

Mr. Morgan: No, we are not prepared.

Examiner Durrance: May I inquire if you have made any effort or what effort you have made to prepare yourself since you had notice of this hearing being set, Mr. Morgan?

Mr. Morgan: I have made no effort to prepare to start putting on proof at this time. We have done a great deal of work, Mr. Examiner, anticipating it might become necessary for us to put on proof. Much of that work was done while this same litigation was pending before the Illinois Commerce Commission, but we have made no preparation to start putting on proof at this time for the reason we did not think it was proper and until we got that notice never dreamed we would be asked to proceed with our proof before the other side had been heard.

Examiner Durrance: Are you familiar with the Commission's rule 50.63?

Mr. Morgan: Yes, sir, I am familiar with it.

Examiner Durrance: Under that rule don't you think you had the right or reason to anticipate you might be designated to put your case on at the opening?

Mr. Morgan: No, sir, I do not think so, for the simple reason I do not think the application being made to the rule is a valid application to the rule. I assume if Mr. Booth and Mr. Keegan representing the complainant in Case No. G-109 were contending for the right to open and close and I was contending for that right the Examiner would have to decide the dispute or the controversy. It was only to that sort of situation I applied that rule. I did not assume the Commission or the Examiner would make an application of it that would deprive us of our constitutional rights in a proceeding of this sort.

Mr. May: It is our understanding you contend the Commission has no right to designate the procedure or that the Examiner has no right to say who shall go forward first under Section 50.63 of the rules, regulations, and practices?

Mr. Morgan: If I have not made my position perfectly clear, that is exactly my position; they have no right to require us.

Mr. May: As I understand your statement you are not challenging the validity of Section 50.63 of the rules, is that correct?

Mr. Morgan: I am only challenging the application, not the validity. There might be circumstances under which the rule is perfectly valid, but not as being applied here.

Mr. May: What is the particular application here to which you object, if you will clear it up in my mind?

Mr. Morgan: I object to the application of a rule requiring us to take the laboring oar, the developing of proof, when the law contemplates we are only here to meet proof. We have our rates, they are prima facie reasonable, and until they are broken down by evidence, not by mere declaration of a party, there is nothing we are required to prove to defend them, except furnish the Commission such information as it is entitled to in conducting an investigation, which information we have not hesitated to give whenever they have asked for it, and it is our purpose to continue to do that.

Examiner Durrance: Gentlemen, there will be a recess for five minutes.

(Whereupon a recess was taken.)

Examiner Durrance: The record may show the hearing will be resumed.

In view of the circumstances that have developed with reference to the procedure I am going to ask that counsel for the Illinois Commerce Commission state his position in connection with that.

Mr. Booth: If the Examiner please, in view of the statement of counsel for the company I briefly would like first to state the interest of the State of Illinois and the Illinois Commerce Commission in this proceeding.

This company, Natural Gas Pipeline Company of America, was first organized either in 1930 or 1931. This line was built and the contracts were entered into with the Chicago District Pipeline Company in 1931. Following the execution of that contract the Chicago District Pipeline Company asked the Commission, the Illinois Commerce Commission, to approve its contract with the Peoples Gas Light and Coke Company and Public Service Company of Illinois, and in order to demonstrate that those contracts under which the Illinois distributing companies were to purchase natural gas were fair and reasonable submitted before the Illinois Commerce Commission testimony as to the estimated profits and earnings of Natural Gas Pipeline Com-

pany and the Texoma Company under its contract with the Chicago District Pipeline Company.

The contract between Natural Gas Pipeline Company and the Chicago District Company was not submitted to the Illinois Commerce Commission for its approval because the contract was of an interstate character and the Commission had no jurisdiction to approve an interstate contract, but the Chicago District Pipeline Company thought that the Illinois Commerce Commission ought to be in position to determine that Chicago District contract with the Peoples Gas Light and Coke Company was reasonable by submitting evidence as to the profits which Natural Gas Pipeline Company and the Texoma Company thought would be earned by them as a result of selling natural gas to the Chicago District Pipeline Company. There was an extended hearing at that time and considerable testimony was presented in part by officers and directors of Natural Gas Pipeline Company of America. They submitted evidence to the effect that it was their belief and they testified that they put their money into the enterprise upon the assumption that during the fifteen-year contract—

Mr. Morgan: Mr. Examiner—

Mr. Booth: Will you please allow me to state the position of the State of Illinois in this proceeding?

Mr. Morgan: I think I know what you are trying to do.

Examiner Durrance: What is your objection, Mr. Morgan?

Mr. Morgan: I wish to make objection to his going into a statement of what the evidence was in that case.

Mr. Booth: I want to state why—

Mr. Morgan: It should not be stated in this record by way of an informal statement. It is evidence. It is the best evidence of what it is.

Mr. Booth: In view of the attack by counsel for the company upon our petition, our position in this case, it is only fair I be given a brief opportunity to state—

Mr. Morgan: I have no objection to his stating the position of the Illinois Commerce Commission, but I object to his going into a detailed statement of what the record shows in a proceeding to which these companies neither were parties—

Mr. Booth: It is related, if the Examiner please, to the reason we are here today.

Examiner Durrance: The Examiner has not made, of course, a careful study of the Illinois Commerce Commis-

sion's complaint. I am assuming counsel is more or less defining the issues set forth in the complaint. Is that correct?

Mr. Booth: I am discussing the background of the filing of this complaint, and I will get to the complaint and petition in just a moment.

Examiner Durrance: You may proceed.

Mr. Booth: They stated that they thought they would earn about six per cent upon the investment—

Mr. Morgan: If the Examiner please, you see where he is going.

Mr. Booth: Of course, I am going to state why we are here, Mr. Morgan, if you will be kind enough to sit down. I did not interrupt you during your argument. I am stating why we are here.

Mr. Morgan: You had a perfect right to make objection.

Mr. Booth: I had plenty of objection and I am going to state them now.

Mr. Morgan: He is going into a statement of something the Chicago District Pipeline Company proved back in a proceeding back in 1931.

Mr. Booth: It is the background.

Mr. Morgan: I want to object to his doing it.

Mr. May: If I may be permitted the observation, if the attorney for the Natural Gas Pipeline Company was permitted to state what may be proved in this record, I think Mr. Booth probably is entitled to show the background of this proceeding in view of the latitude that was given to counsel for the company.

Mr. Morgan: There is no relation or similarity between what I said and what he is doing. I merely stated my position and stated the basis for it. He is going back over hearsay and telling what was proved in another lawsuit either eight years ago or nine years ago.

Examiner Durrance: Mr. Morgan, he is not offering that as a matter of testimony, as a matter of evidence. Now, if his statement is going to clarify the record it might be helpful to the Commission in the determination of their final appraisal of all the evidence. I see no reason why it should not go into the record.

Mr. Morgan: It could not possibly help clear the position of the Illinois Commerce Commission. It is just his old song he sang before the Examiner, before the Commission proceedings and his own Commission would not per-

mit him to prove what he is now stating happened in that proceeding.

Mr. Booth: I would like to go forward with this case. I will take only five or ten minutes to state our position in this case, if the Examiner please.

Examiner Durrance: You may proceed.

Mr. Booth: That in substance was the testimony of a Mr. Gallagher who was a director of the Natural Gas Pipeline Company. He stated they thought they would earn about six per cent upon their investment during the life of the contract. Subsequently, the Commission found it necessary, however, to disapprove certain provisions in the proposed contract between Chicago District and Peoples Gas Light and Coke Company. Chicago District then went into the federal courts and obtained a preliminary injunction against the enforcement of the Commission's order. Evidence was taken before a Special Master as to the life of the natural gas field. The evidence that was taken before the Commission was submitted in that case. Subsequently, the case was compromised and the Chicago District Pipeline Company was permitted to file a schedule of rates with the Illinois Commerce Commission which substantially embodied the provisions of its contract with Natural Gas Pipeline Company of America.

However, up to that time there was no information available as to the actual profits which Natural Gas Pipeline Company was earning out of the sale of gas to the Chicago District Pipeline Company. In 1936 the Peoples Gas Light and Coke Company filed a petition with the Illinois Commerce Commission, and that is set forth in our complaint, or our petition, asking for a substantial increase in its rates to its domestic users in the city of Chicago. Thereupon, hearings of an extended nature commenced before the Illinois Commerce Commission in connection with this application.

The Commission then, in order to determine whether or not the rates paid by Peoples Gas Light and Coke Company for natural gas were fair and reasonable instituted a proceeding against the Chicago District Pipeline Company to show cause why its wholesale rates for natural gas to the Peoples Gas Light and Coke Company should not be reduced. Information had been brought to the attention of the Commission through reports on file by this company with the Securities and Exchange Commission to the effect its earnings possibly were substantially larger than had

been estimated in the earlier proceedings before the Commission. The Illinois Commerce Commission in the Chicago District Pipeline Company proceeding then entered an order against this company, asking it to make available its books and records to the Illinois Commerce Commission and to submit evidence as to its actual earnings and actual profits arising out of the sale of natural gas to the Chicago District Pipeline Company. Natural Gas Pipeline Company of America refused to comply with the Commission's order and brought suit in the federal courts. They were denied relief in the lower federal courts and appealed to the United States Supreme Court, which in November or December of 1937 held the Illinois Commerce Commission had a right to have access to the books and records of the Natural Gas Pipeline Company of America in the Chicago District Pipeline Company proceedings.

The Commission then, as Mr. Morgan indicated in his argument, for the first time had access to the actual profits of the Natural Gas Pipeline Company of America under its contract with the Chicago District Pipeline Company, and as we have set forth, some 90 per cent of the natural gas sold by this company is sold to the Chicago District Pipeline Company and then in turn to the Illinois distributing companies, principally Peoples Gas Light and Coke Company. The testimony as to the profits, the actual profits of Natural Gas Pipeline Company in the sale of natural gas to the Chicago District Pipeline Company was then submitted to the Illinois Commerce Commission. Natural Gas Pipeline Company intervened in that case. They began, as Mr. Morgan indicated, the preparation of extensive evidence dealing with the value of its property, dealing with the question as to what is a fair rate of return, dealing with the question as to the life of its natural gas field, as to its investment and many other factors.

However, about the same time Congress was considering House Bill 4008, and finally this bill, which is the basis of the Federal Power Commission's jurisdiction in this case, was enacted into law. Thereupon, the Natural Gas Pipeline Company of America contended before our Commission we had no right to give any consideration to the profits of Natural Gas Pipeline Company of America because of the fact Congress by the adoption of a natural gas act in 1938 had vested in your Commission direct complete and exclusive authority to determine the reasonableness of interstate wholesale contracts.

The Illinois Commerce Commission then filed its petition on the 21st day of September, 1938, setting forth that the earnings of this company from 1932 up to 1937 had increased annually from $3,641,000 to $10,795,327. In 1936 and 1937 the earnings of this company and the Texoma Company, before an allowance for depreciation and amortization as this petition sets forth, exceeded $10,000,000. It also set up that the investment in this company, the gross investment as of December 31, 1937, was approximately $65,000,000, that the dividends paid by Natural Gas Company on its capital stock in 1936 amounted to $2,775,000 on the $3,000,000 outstanding common stock and $4,125,000 in 1937, a dividend in excess of 100 per cent in 1937. It stated that based upon an amortization period of twenty years which had been originally found by the Commission that the Company had already earned 8.2 per cent (from 1931 through 1937) on its average gross investment, and that for 1937 the earnings were 13.4 per cent upon its total investment, taking amortization and depreciation on the 20-year basis.

The earnings as set forth in this petition were admitted by Natural Gas Pipeline Company of America in its answer. On its face our petition clearly establishes that the existing rates of Natural Gas Pipeline Company to the Chicago District Company are unfair and unreasonable because of the current excessive earnings of the Natural Gas and the Texoma companies.

Now, we say that the rule and regulation adopted by this Commission under Section 50.63 of its rules is eminently fair and reasonable in the situation. This contract and all the contracts between Natural Gas Company and the Chicago District and other companies were not approved by any regulatory authority. There is no prima facie showing of reasonableness of those contracts merely because they have been filed with this Commission. This company has been engaged for over a year and a half, as Mr. Morgan admitted in his opening argument, in the preparation of testimony bearing upon the reasonableness of its rates. It is in the best position to advise this Commission as to what its earnings are, as to what its investment is, as to what the value of its property is, as to the life of its fields; all that information, and a substantial part of it is in the books and records and is within the knowledge of the officers and directors or the experts employed by this company. We say under the circumstances it is

absolutely appropriate that the company proceed and endeavor to convince this Commission that the contracts which it entered into with Chicago District Pipeline Company and these other companies are in fact fair and reasonable and that they have nothing to conceal, or nothing to hide. They ought to be eager and willing under these circumstances to place before your Commission the facts bearing upon its earnings and expenses upon its entire operations.

Furthermore, in view of the fact that this Commission has entered an order under its rules, of which this company has had notice, to open this case and present evidence bearing upon its operations, that unless the company does proceed we believe it will be quite proper for the Examiner and the Federal Power Commission to rule that the company has waived its opportunity, its right to make out a direct showing as to reasonableness of its earnings, investments, expenses and other factors bearing upon the reasonableness of its rates, and if it fails to go forward and if the Federal Power Commission and we are compelled to go forward first that the only testimony which Natural Gas Pipeline Company of America shall be permitted to present in this case would be testimony of a rebuttal character.

Examiner Durrance: Does the Commission's counsel have anything to say?

Mr. May: I would like to make a statement. As I understand it Mr. Morgan, among other things, implied his company had not been given adequate notice, did not know what was involved in the Commission's investigation, what particular rates were under consideration, and so forth. I want to clear up that point in the record. The ordering paragraph of the Commission's order of October 14, 1938, Docket No. G-112, instituting an investigation, reads as follows:

"An investigation of the Natural Gas Pipeline Company of America and the Texoma Natural Gas Company be and is hereby instituted, for the purpose of enabling the Commission: (1) to determine, with respect to each of said companies, whether, in connection with any transportation or sale of natural gas subject to the jurisdiction of the Commission, any rates, charges, or classifications demanded, observed, charged or collected, or any rules, regulations, practices, or contracts affecting such rates, charges, or classifications, are unjust, unreasonable, unduly discriminatory, or preferential; and (2) if the Commission

shall find that any such rates, charges, classifications, rules, regulations, practices, or contracts are unjust, unreasonable, unduly discriminatory, or preferential, to determine and fix by appropriate order or orders just, reasonable, and non-discriminatory rates, charges, classifications, rules, regulations, practices, or contracts to be thereafter observed and in force."

Now, Mr. Examiner, it appears to the Commission counsel in view of the very broad provisions in the Commission's order that the company certainly had notice that all its rates and charges were under consideration in this investigation proceeding, and further that the Commission in this very proceeding would determine what were the just and reasonable rates to be charged by the company. I think nothing could be more explicit and the company should certainly not claim here they did not know what was involved in the investigation proceedings.

As I understand it, with respect to the order of procedure, Mr. Examiner, the company does not attack the validity of Rule 50.63, but its application in this proceeding. Personally I think—Mr. Morgan has stated he has been preparing for this proceeding and other proceedings for a long time, you will notice no application has been made to the Commission for continuance of this hearing in order to enable the company to present evidence, but instead the company relies upon their construction of the rule and the validity of its application—and I think that the company might have exerted some effort to get ready for this hearing rather than coming down to the very day of the hearing and taking the position that they have taken.

Of course, as it appears in this record, the company has chosen not to comply with a direction of this Commission they should open and close this proceeding. What action the Commission will take in view of that turn of events, personally, I don't know. I think, Mr. Examiner, that if the company insists upon that position, in order to expedite this case and get all of the facts the Commission is desirous of getting into this record as promptly as possible, and to avoid delay, that this proceeding should continue and the Federal Power Commission and the Illinois Commerce Commission, if it chooses to adopt that course, should begin the presentation of evidence, as I say, solely for the purpose of avoiding delay in this proceeding. The Commission is anxious to get all the facts just as soon as possible. I am sure if the company or the

companies involved here will cooperate in that effort we will all be better off.

Mr. Morgan: Mr. Examiner, if I may be permitted to add just a word to what I said in reply to the statements of these gentlemen.

I have not said we have been engaged for a year and a half in preparing evidence for this proceeding or any similar proceeding. What I said was throughout last year we spent several months preparing proof concerning our valuations and other facts which we thought might become pertinent, bringing the figures, however, down to the first of January, 1938. We have not continued those figures on down to date for the reason we don't know to what date to continue them, and it is very expensive, as the Examiner doubtless knows, to employ valuation experts and others dealing with a vast problem of this kind, and we naturally want to avoid the necessity of employing them over and over again to do that.

Now, I have not said I do not know what the subject of the Power Commission's inquiry is. I took the pains to state in detail what the inquiry covers. I know what it covers but I do not know what complaint they will have against us when they have completed their inquiry. That is my position here. We are only required to meet the complaint of the Illinois Commerce Commission on the evidence that it brings here and such evidence as the Federal Power Commission sees fit to bring here and offer against us. We are not denying the Federal Power Commission all the information the law contemplates. As I have already said we are very willing to give it to them. I think if they will check with their representatives who have contacted us in an effort to conduct this investigation they will find we have cooperated completely with their representatives in every particular, to the extent of spending a very substantial sum of money already in an effort to cooperate with them. We are perfectly willing to give them the figures. Our only position is we are not required to make this lawsuit but required only to meet it and that is the position on which we stand.

Examiner Durrance: I understand, Mr. Morgan, you are in position at this time to rebut any testimony which either Commission might offer at this hearing?

Mr. Morgan: No, I am not in position to do that. I don't know what they will offer. When they have offered it I will then have to pass on that question. I anticipate if they cover the case as the law requires them to cover it

we will have to have some time before we can proceed. However, it will not be mere rebuttal. It will be direct testimony going to the respondents' or defendants' defenses in this case and I am not waiving any right to defend ourselves on direct testimony, notwithstanding Mr. Booth's suggestion we ought not to be permitted to have that right.

Examiner Durrance: The Examiner is not in position at this time to state what position the Commission will take with reference to the defendants' failure or refusal to comply with its orders. However, we will proceed in accordance with the suggestion of Commission's counsel to take the testimony and the Examiner will determine before the proceedings are adjourned whether or not the defendant will be foreclosed from putting in direct testimony.

Mr. Booth: May the record show if we do proceed, and we want to take at least during the noon hour and possibly until tomorrow to determine when we can proceed, that it is not to be considered as assuming the burden in this case or waiving any right which the Federal Power Commission may have to take any steps against the company under the provisions of the Act for failure to comply with the direction and regulation and order of the Federal Power Commission?

Mr. May: Of course, the Commission's counsel understand if we proceed to take evidence there will be no waiver of any right of the Commission to take such action to enforce its directional order as it may deem advisable.

Examiner Durrance: That is correct. Are you ready to proceed with the Illinois Commerce Commission's testimony, Mr. Booth?

Mr. Booth: No, we are not ready at this time. As I stated, we would like to come back at the afternoon session and advise the Examiner when we will be ready to proceed. I think we will be ready to proceed some time during the week but, obviously, we assumed in view of the rule of the Power Commission that the company would put on its case first. Mr. Morgan's decision requires some changes in our plans. We have been engaged in the preparation of certain types of testimony and we will be ready, if we decide to go ahead, some time during the week, it may be Wednesday or it may be Thursday, and I believe I will be in better position to advise you fully on our return this afternoon. I understand, however, Mr. May has some jurisdictional testimony and other testimony to present.

1 ABSTRACT OF TESTIMONY.

CLAUDE C. BROWN testified on behalf of the Federal Power Commission as follows:

Direct Examination by Mr. May.

My name is Claude C. Brown. I have been employed since September 1, 1938, by the Federal Power Commission as principal gas engineer, in charge of the Natural Gas Section of the Bureau of Engineering. My duties involve the supervision and direction of all gas engineering work performed in connection with the regulation of the transportation and sale of natural gas in interstate commerce.

I graduated from the University of California in 1914, receiving the degree of Bachelor of Science in mechanical and electrical engineering. In the years 1928 and 1929 I studied petroleum geology in the University of Southern California.

From the year 1904 to the year 1922 I held engineering positions during various periods with the following agencies: Pacific Light & Power Company, Lewellyn Iron Works, Baker Iron Works, Southern California Edison Company, Southern Pacific Railroad Company, J. G. White Engineering Corporation, Northern California Power Company and Pacific Gas & Electric Company. The duties in these positions involved construction, operation, valuation and various other general engineering work.

During the years 1917 and 1918 I was in the engineering corps of the United States Army.

In November of 1922 I became connected with the California Railroad Commission, in the capacity of assistant valuation engineer, engaged in the appraisal of various gas and electric utilities.

During the years 1924 and 1925 I had the position of assistant engineer in the Gas and Electric Division of that Commission, performing engineering and rate work in connection with natural gas, manufactured gas, and electric matters.

During 1926 and 1927 I held the position of gas engineer with that Commission, handling all gas matters, involv-
2 ing both natural and manufactured gas, including engineering and rates.

During 1928 and 1929 I held the position of Gas Administrator for the State of California, being responsible for the allocation of the natural gas supply in that state.

From 1929 to 1933 I held the position of gas and electric engineer with the California Commission, in charge of the gas and electric division, and had supervision of all gas and electric engineering and rate matters that came before the Commission.

During the years 1929 and 1930 I also acted as consulting gas engineer for the Department of Natural Resources of the State of California. This work had to do with the administration of conservation legislation for the purpose of reducing the then existing wastage of natural gas in that state; also the estimation of natural gas reserves; and estimates and studies of the production, transmission, utilization and wastage of natural gas; and studies of the markets for natural gas.

From 1933 to 1937 I held the position of chief engineer for the California Railroad Commission, in charge of the engineering department, and was responsible for all engineering and rate work performed by that department, including all phases of state regulation of natural and manufactured gas, electric, telephone, water, and transportation utilities. This work included rate cases, cases involving the application for certificates of public convenience and necessity, and all other types of proceedings involving engineering phases.

From 1937 to September 1, 1938, I held the position of chief consulting engineer for the California Commission, handling all engineering matters and special problems during that period. I also performed general consulting engineering work, dealing largely with the production, transmission and distribution of natural gas.

On September 1, 1938, I accepted my present position with the Federal Power Commission.

I have had a rather wide experience in all phases of regulation of gas utilities, both natural and manufactured, including production, gathering, transmission, distribution, purchase and sale of gas, and the costs of same; also the construction, operation, valuation of gas properties and facilities, and the preparation and handling of rate cases, certificate cases, and other proceedings.

I have had experience in the estimation of natural gas reserves. I was retained by the Texas Company as one of

a number of consulting engineers to determine the extent of their reserves in the Kettleman Hills field, California.

I also made estimates of the reserves of the Butte Oil Fields, Incorporated, which has holdings and operates in the same state.

3 I also made many estimates of reserves in connection with my work with the California Railroad Commission, and as consulting gas engineer for the Department of Natural Resources, and others.

I have tested gas wells at various times and in various fields in California.

I am familiar with the Hugoton gas field in southeastern Kansas and the Texas Panhandle field. I have been in those fields and was last there in March, 1939, at which time I conferred with Messrs. Dickinson, the manager of the Texoma company at Amarillo; Martin in the land department of the same office; Mr. Peterson, geologist for Texoma; Mr. Powers, in charge of the Fritch compressor station; and Mr. Williams, who has to do with the pipelines of the Texoma company.

I also conferred with Mr. Ford, manager of the Canadian River Gas Company at Amarillo; Mr. Walton, manager of the Republic Natural Gas Company at Hugoton; Mr. Batten, in charge of the Pampa station of Cities Service Gas Company; and Messrs. Harrington and Marsh, of Hagy, Harrington & Marsh, holders of acreage in those fields.

I visited the Fritch compressor station of Texoma, the Bivins compressor station of Canadian River, the Pampa compressor station of Cities Service, the Skellytown compressor station of Northern Natural Gas Company, Cabot carbon black plant, and various gas wells and leases in that area.

In March I conferred with the staff of the Texas Railroad Commission in Austin, Texas.

I am familiar with the operations and facilities of Texoma Natural Gas Company and Natural Gas Pipeline Company of America.

(Map entitled "Texoma Natural Gas Company—Panhandle Gas Field of Texas," marked Exhibit No. 1 for identification.)

Exhibit 1 was secured by me from Texoma Natural Gas Company. This map shows in red lines the gathering lines of Texoma in the Texas Panhandle field. Located in the center of the map, marked "Station No. 1," is located the Fritch compressor station of Texoma.

Into that station there is led two gathering trunk lines, one extending from what is known as the East field of the Texas Panhandle, down in the low : right-hand corner of this map, and extending in a northwesterly direction to the Fritch station, and the other extending from the main portion of the Texas Panhandle field, or what is known as the West field, in the upper left-hand corner of this map, and extending generally in a southeast direction to the same Fritch compressor station.

This map also shows a portion in green of the transmission line from Fritch compressor station, extending in a northeasterly direction, and going off this map, extending on up to what is known as Gray Junction in Oklahoma. This map shows the sizes of the various gathering lines of the company, the two main trunk lines being 24 inch and the laterals therefrom varying in size from 4 inches to 18 inches.

4 The total length of lines, as indicated on this map, is 220.497 miles, consisting of the following:

78.761 miles of 24 inch lines
.374 miles of 18 inch lines
5.105 miles of 16 inch lines
.107 miles of 12 inch lines
20.326 miles of 10 inch lines
34.114 miles of 8 inch lines
44.518 miles of 6 inch lines
37.192 miles of 4 inch lines

(Map entitled "Natural Gas Pipeline Company and Texoma Natural Gas Company — Communities Served by Natural Gas Pipeline Company," marked Exhibit 2 for identification.)

Exhibit 2 is a map obtained by me from Natural Gas Pipeline Company of America. This map shows a continuous 24 inch gas transmission line from the Fritch compressor station in the Texas Panhandle field to a point near Joliet, Illinois, with delivery taps therefrom.

Including the river crossings and laterals, this line is 988.976 miles in length. That portion of the line owned and operated by Texoma from Fritch compressor station in Texas to Gray Junction, Oklahoma, is shown in green. The Panhandle field is shown in the lower left-hand corner of this map, and marked. This portion of the line includes 73.598 miles in Texas and 4.818 miles in Oklahoma, or a total of 78.416 miles from the Fritch compressor station to Gray Junction, Oklahoma.

That portion of the line owned by Natural Gas Pipeline Company of America, from Gray Junction, Oklahoma, to Joliet, Illinois, is shown in red. The taps off that line are shown in yellow. That line includes 43.554 miles in the State of Oklahoma, 302.809 miles in the State of Kansas, 100.225 miles in the State of Nebraska, 285.336 miles in the State of Iowa, and 178.936 miles in the State of Illinois, or a total of 910.560 miles from Gray Junction, Oklahoma, to Joliet, Illinois.

Tap lines are the laterals, shown in yellow, extending laterally from the main lines. The two main transmission lines are shown, as explained; the one owned and operated by Texoma in green and that owned and operated by Natural Gas Pipeline Company of America in red. The tap lines, or the branch lines, extend from these main transmission lines and are indicated on this map in yellow. Those are what I referred to as tap lines.

Texoma Natural Gas Company and Natural Gas Pipeline Company of America maintain executive offices at 20 North Wacker Drive, Chicago, Illinois.

The Texoma company maintains an office in the Rule Building, Amarillo, Texas. The personnel in that office supervise and perform Texoma leasings, right of way, geological and well drilling operations. They also calculate all rates, measurement of gas and perform bookkeeping pertaining to royalty, rentals, gas production taxes, etc.

5 The pipeline personnel of the company is directed from its Fritch compressor station. Texoma controls approximately 153,795 acres of gas leases in the Texas Panhandle field. It produces natural gas from its wells on these leases and collects the same through its two main gathering systems, one extending from Gray County, Texas, through Carson and Hutchinson Counties, Texas, and the other from Moore County, Texas, to its compressor station located near Fritch, in southwestern Hutchinson County, Texas.

The Canadian River Gas Company delivers gas to the facilities of Texoma near Fritch for delivery to Natural Gas Pipeline Company of America and for sale to the latter company by Colorado Interstate Gas Company.

The Texoma company extracts gasoline from all the gas that passes through its Fritch plant.

From its Fritch compressor station Texoma delivers gas through its 24 inch transmission line to Natural Gas Pipe-

line Company of America at a point near Gray, Oklahoma, known as Gray Junction.

The Fritch compressor station of Texoma contains fifteen 1250 horsepower Worthington horizontal gas engine-driven compressor units, together with all necessary auxilliaries. At the time of my visit to that station in March, 1939, fourteen of these units were in operation, with one unit down for overhauling.

The intake pressure on one of the gathering lines leading into the Fritch station was 180 pounds per square inch gauge. On the other two gathering lines coming in it was 220 pounds. The discharge pressure from the compressor units was 745 pounds per square inch. The station at that time was handling approximately 230 million cubic feet per day.

Other equipment at the Fritch station includes a high-pressure gasoline extraction and fractionating plant, a calcium chloride dehydrating plant, an electric powerhouse, machine shop, warehouse, chemical laboratory, field office, garage, community hall, and employees' residences. It also has atmospheric cooling towers, heat exchangers; oil, gasoline, Butane, and water storage tanks; also scrubbers, circulating system, etc. Tools, repair equipment, transportation equipment, and stocks of pipe and other supplies are held at Fritch, in Hutchinson County; also at Kingsmill, in Moore County, and Dumas, in Moore County, Texas.

Texoma does not purchase any gas from others, but produces all of its own natural gas.

(Document entitled "Texoma Natural Gas Company—Production and B.T.U. by Fields for Year Ending June 30, 1938," marked Exhibit 3 for identification.)

Exhibit 3 is a tabulation, prepared under my direction, showing by months for the period from July, 1937, to June, 1938, the volumetric amount on a 16.4 pressure basis of natural gas produced by Texoma from its leases in the Texas Panhandle oil and gas field and the average heating value thereof. The source of this information was Texoma's response to Question 9-A of the Commission's Order No. 51.

6 This exhibit, consisting of one sheet, shows for each month from July, 1937, to June, 1938, inclusive, the production of natural gas by Texoma in the Texas Panhandle field, and the reported heating value in BTU's per cubic foot thereof. The total for the 12 months is 52,289,039 MCF for the total 12 months period, and the average heat-

ing value of that gas is reported as 1,082 British Thermal Units per cubic foot.

(Document entitled "Texoma Natural Gas Company—Gas Sold or Delivered by Companies for Year Ending June 30, 1938," marked Exhibit 4 for identification.)

Exhibit 4 is a tabulation, prepared under my direction, showing for the 12 months period ending June 30, 1938, the volumetric quantities of natural gas on a 16.4 pound pressure base sold by Texoma to each of its customers, the points of delivery, and the ultimate purposes for which such gas was used. The total volumetric sales for that period were 50,478,161 MCF. The source of this information was Texoma's response to Question 9-D of Order No. 51 of the Federal Power Commission.

(Document entitled "Texoma Natural Gas Company—Consolidated Operating Analysis—Gas Balance—M.C.F.—16.4# Pressure Basis," marked Exhibit 5 for identification.)

Exhibit 5, prepared under my direction, is a tabulation showing the volumetric natural gas receipts and disbursements on a 16.4 pound pressure base, by years, for the calendar years 1934 to 1938 inclusive by Texoma. The source of this information was the company's records.

(Document entitled "Texoma Natural Gas Company—Natural Gas Division—Earnings Analysis," marked Exhibit 6 for identification.)

Exhibit 6, prepared under my direction, is a tabulation showing, by years, for each of the calendar years 1934 to 1938, inclusive, the annual revenue received by Texoma from its customers. The source of this information was the records of Texoma.

Texoma has filed with the Federal Power Commission, in compliance with Commission Order No. 53, one natural gas sales agreement or contract, dated October 15, 1931, with Natural Gas Pipeline Company of America. This was filed on August 22, 1938. The term of the agreement is from October 15, 1931, until and including September 30, 1946, and so long thereafter as Texoma has available for delivery to Natural Gas Pipeline Company of America quantities of natural gas which, in the opinion of Natural Gas Pipeline Company of America, are profitable for it to purchase.

Under this agreement Texoma, seller, agrees to sell and deliver to Natural Gas Pipeline Company of America, buyer, and buyer agrees to purchase and receive from

seller, at a point known as Gray Junction, located near Gray, Beaver County, Oklahoma, said point being the junction point between seller's 24 inch gas transmission line from its Fritch compressor station and buyer's 24 inch gas transmission line extending from said junction point to a point near Joliet, Illinois, all of the natural gas in excess of the quantity thereof purchased by buyer from Colorado Interstate Gas Company under an agreement between buyer and Colorado Interstate Gas Company dated October 15, 1931.

That latter quantity, namely the amount of gas purchased by Natural Gas Pipeline Company of America from Colorado Interstate Gas Company, approximates 25% of its requirements.

7 So that under this agreement the Natural Gas Pipeline Company of America agrees to buy from Texoma all the gas which is required by the buyer, with the exception of the amount stated, to supply its present or future customers supplied with natural gas through buyer's pipeline from Gray, Oklahoma, to Joliet, Illinois; and any additions thereto, any enlargements or extensions thereof, hereafter constructed for the transportation and delivery of gas to any point.

Under this agreement the buyer has first call at all times upon all of the natural gas produced by seller (I refer there to Texoma as seller) from seller's gas lands, gas leaseholds, gas rights, gas reserves or gas wells, presently held or thereafter acquired by seller; after deducting therefrom any quantity of natural gas which the seller may have supplied to any of its customers for consumption in Parmer, Castro, Swisher, Briscoe, Hall or Childress Counties, Texas, or any county north thereof in the State of Texas. Under this contract the title to the gas sold and delivered by seller to buyer passes from seller to buyer at Gray Junction.

Furthermore, under this contract seller agrees to develop, operate, extend and renew all of its present or future gas lands, leases, rights and properties in such manner as to produce sufficient natural gas for delivery under the agreement.

The agreement also provides that if necessary the buyer, that is, Natural Gas Pipeline Company of America, agrees to loan to seller at an interest rate of 6% per annum amounts of money required to drill additional wells or make such improvements and conduct such operations as

are necessary to enable seller to produce and deliver to buyer the latter's natural gas requirements under the agreement.

It is specified in the agreement that the natural gas sold and delivered under said agreement shall be free from solids or liquids, shall not contain more than one grain of hydrogen sulphide nor more than 30 grains of total sulphur per 100 cubic feet, and shall have a heating value of not less than 1000 British Thermal Units per cubic foot.

The unit of volume of natural gas under the contract is one cubic foot at a base temperature of 60 degrees Fahrenheit, and at an absolute pressure of 16.4 pounds per square inch at Gray Junction, and that the delivered pressure at Gray Junction of this gas shall be up to 600 pounds per square inch gauge, as may be required by buyer.

The rate per 1000 cubic feet of gas delivered in any month to be paid for by buyer to seller is determined for said month as the sum of two components. These two components consist, first, of the total production cost per MCF for the particular month involved, and, second, the total gathering, compressing, transporting, and metering costs per MCF for that month.

The production cost for each month is determined by adding all rentals on leaseholds, gas rights, gas estates, royalties on gas wells and gas production, all operating and maintenance costs of producing equipment and operating wells, and two-thirds of the unallocated general, administrative and office expenses, other than so much
8 thereof as are charged by the seller to the operation of its gasoline extraction plant at Fritch; and adding further a pro rata on the basis of investment in production capital to the total investment of all payments by seller to the Chase National Bank of the City of New York, which bank is a trustee under a certain indenture dated October 15, 1931, and given by seller to that bank; and to the holders of bonds or coupons issued thereunder; also all amounts of capital and interest paid to buyer on loans which may have been made to seller by buyer that have been expended for production capital; and also all costs of metering gas at the wells, insurance, taxes covering the ownership and operation of production equipment, with the exception of taxes on net income or net profits; and after those total items have been added up, then dividing that total sum by the MCF of natural gas delivered by seller to all purchasers during such month. That then gives the estimated produc-

tion cost under this agreement and forms one component of the monthly price paid.

The second component is determined by adding the gathering, compressing, transporting and metering costs for each month; by adding all of the costs of maintaining and operating gathering lines, compressor stations, main lines, meters and other equipment used in the gathering, compressing, transporting and delivering of natural gas; and adding also one-third of the unallocated general, administrative and office expense, other than that portion charged to the gasoline plant; also a pro rata on the basis of investment in gathering, compressing, transporting and delivering equipment to total investment; also all payments by seller to the trustee that I mentioned a moment ago, and the holders of bonds or coupons issued under that indenture; also all amounts of capital and interest paid to buyer on loans made to seller that have been expended for gathering, compressing, transporting and delivering capital; also all insurance and taxes covering ownership and operation of such facilities, with the exception again of taxes on net income or net profits; and deducting from this total then all amounts received from Canadian River Gas Company on account of rent and expense of operation under a certain lease and operating agreement dated October 15, 1931, between seller and Canadian River Gas Company, wherein this seller assigned to the Canadian River Company a 25% interest in its facilities for mainline transmission; and ther dividing that difference by the MCF of natural gas transported through such gathering pipelines, main pipelines, and compressor stations, and sold by seller during the month.

Those two costs, those two components, are then added to form the cost per MCF for any particular month that Texoma charges Natural Gas Pipeline Company.

(Contract between Texoma Natural Gas Company and Natural Gas Pipeline Company of America dated October 15, 1931, incorporated in the record by reference without objection.)

I am able to give the total annual volumetric sales by Texoma to Natural Gas Pipeline Company on a 16.4 pound pressure base and the average rate received per MCF for each of the calendar years 1934 to 1938. For 1934 the total MCF sales were 31,865,440 MCF, and the average annual rate for those sales was 8.9453 cents per MCF. For 1935 the sales were 39,360,284 MCF, and the aver-

age rate was 8.1517 cents per MCF. For 1936 the sales were 48,795,294 MCF, and the average rate was 7.8150 cents per MCF. For 1937 the sales were 52,742,027 MCF, and the average rate was 5.8852 cents per MCF. For 1938 the sales were 46,263,244 MCF, and the average rate was 7.5884 cents per MCF.

The source of the information I have just given is the records of Texoma.

With respect to the operations and facilities of Natural Gas Pipeline Company, I will state that Natural Gas Pipeline Company owns and operates a 24 inch natural gas transmission line extending from a point near Gray, Oklahoma, known as Gray Junction, the point of junction between said line and Texoma's 24 inch gas transmission line from Fritch, Texas, to a point near Joliet, Illinois.

Nine compressor stations are located on this main transmission line, approximately 90 miles apart. Sectionalizing valves are located on the line at approximately 10 mile intervals. Cross-tie connections and meter setups are installed for emergency use at points where the line crosses the Panhandle Eastern line near Fowler, Kansas; also where it crosses the Cities Service line near Lincoln, Kansas; and also where it crosses the Northern Natural line near Pacific Junction in Iowa. From this main transmission line gas is delivered to customers in Oklahoma, Kansas, Nebraska, Iowa and Illinois.

Natural Gas Pipeline Company produces no gas. It purchases all of its gas from two sources, Texoma and Colorado Interstate Gas Company. Natural Gas Pipeline Company's response to Question No. 9-B of Order 51 of the Federal Power Commission shows that during the 12 months period ending June 30, 1938, Natural Gas Pipeline Company purchased from Texoma 49,616,993 MCF, and from Colorado Interstate 17,227,770 MCF, or a total from the two companies of 66,844,763 MCF. These volumes are on a 16.4 pound pressure base.

(Document entitled "Natural Gas Pipeline Company of America—Gas Sold or Delivered—By Companies For Year Ending June 30, 1938," marked Exhibit 7 for identification.)

Exhibit 7, prepared under my direction from Natural Gas Pipeline Company's response to Question 9-A of Order No. 51 of the Federal Power Commission, is a tabulation showing for the 12 months period ending June 30, 1938, the volumetric quantities of natural gas on a 14.65 pound pres-

sure base sold by Natural Gas Pipeline Company to its customer companies, the points of delivery, and the ultimate purposes for which such gas was used. The total volumetric sales for that period were 70,795,402 MCF on a 14.65 pressure base, which would be the equivalent of 63,241,016 MCF on a 16.4 pound pressure base.

(Document entitled "Natural Gas Pipeline Company of America—Purchased Gas," marked Exhibit 8 for identification.)

Exhibit 8, prepared under my direction from the records of Natural Gas Pipeline Company, is a tabulation showing by years for each of the calendar years 1934 to 1938, inclusive, the annual volumetric purchases of natural gas by Natural Gas Pipeline Company from each source, on a 16.4 pound pressure base, and the amounts of money paid for such purchases.

(Document entitled "Natural Gas Pipeline Company of America—Consolidated Operating Analysis—Gas Purchases and Sales—M.C.F.," marked Exhibit 9 for identification.)

Exhibit 9, prepared under my direction from the records of Natural Gas Pipeline Company, is a tabulation showing by years for each of the calendar years 1934 to 1938, inclusive, the natural gas receipts and disbursements, on a 14.65 pound pressure base, by Natural Gas Pipeline Company.

(Document entitled "Natural Gas Pipeline Company—Gas Sales—14.65 pound Pressure Base," marked Exhibit 10 for identification.)

Exhibit 10, prepared under my direction from the records of Natural Gas Pipeline Company, is a tabulation showing by years for each of the calendar years 1934 to 1938, inclusive, the annual volumetric sales of natural gas on a 14.65 pound pressure base by Natural Gas Pipeline Company, and the amounts of revenue received from such sales.

(Document entitled "Natural Gas Pipeline Company of America—Natural Gas Sales Agreements," marked Exhibit 11 for identification.)

Exhibit 11 is a list of the natural gas sales agreements or contracts filed by Natural Gas Pipeline Company with the Federal Power Commission in compliance with the Commission's order No. 53. This exhibit shows the name of the customer, the date of the agreement, the effective date of the agreement, the date of filing, and the designated

Federal Power Commission number of the tariff. This exhibit consists of three sheets. The agreements referred to therein are now on file with the Federal Power Commission.

(Contracts filed by Natural Gas Pipeline Company of America with the Federal Power Commission, listed in Exhibit 11, incorporated in the record by reference without objection.)

I am familiar with the location and structure of the Texas Panhandle oil and gas field, located in the Texas Panhandle, State of Texas. I have heretofore testified that I have been in that field. I have a map showing the location of that field and its generally accepted productive limits. This map was obtained by me from the Texas Railroad Commission.

(Map entitled "Pressure Contour Map Panhandle Gas Fields, July, 1938," marked Exhibit 12 for identification.)

11 Exhibit 12 is the map referred to. It is entitled "Pressure Contour Map Panhandle Gas Fields, July, 1938," and shows on its face that it was prepared by the Railroad Commission of Texas.

This map shows by heavy black lines the outside boundary of the oil and gas producing area of the Texas Panhandle field. That outside black line I mean is the one I am indicating now on the map. It is the heavy black line outside of all the coloring on the map. The oil producing area in this field is a strip extending along the northeastern boundary of the field where I am indicating at the present time—the northeastern flank of the field. The balance of the field included in the heavy black line, other than the oil producing area, is the natural gas producing area of the field. The uncolored island, you might call it, in the lower right-hand corner of the map, located about in the center of Gray County, Texas, is apparently a barren area, apparently barren of either oil or gas.

The gas area on this map is contoured and colored according to the 1938 gas pressure survey conducted by the Texas Railroad Commission, in which the shut-in wellhead pressures were found to be certain amounts as indicated on the map. That portion of the map that is colored with kind of a gray-black on the northeastern flank indicates an area in which the pressure was found to be below 150 pounds; that is, the shut-in wellhead pressure of the wells averaged below 150 pounds gauge.

The next band of color, namely, this orange color extend-

ing next to the black is a band wherein the well pressures were found to vary from 150 to 200 pounds per inch gauge.

The next one, which is a sort of a brown color, is one in which the pressures were found to be from 200 to 250.

Next to that is the red, in which the pressures vary from 250 to 300 pounds, and next to that is the blue which shows pressures from 300 to 350. Then next to that is the green area, which it will be noted covers a substantial portion of the field, where the pressure varies from 350 to 400, and finally the yellow, in which the pressures are 400 pounds and above.

12 Before I leave that point I would like to make a statement. The weighted average shut-in wellhead pressure of the gas areas of the field as of July 31, 1938, was found by the Texas Railroad Commission to be 337.66 pounds per square inch gauge.

This map also shows a dotted line extending from a point somewhere south of Pampa in Gray County in a northwesterly direction through the field and extending almost to the westerly boundary of the field and then cutting down into the southwest boundary. That line is a dividing line between what is known as the sweet gas and sour gas area, the area south of that line producing sweet gas and north of it the so-called sour gas, or gas containing substantial amounts of sulphur, hydrogen sulphide.

This Texas Panhandle field is divided into two fields by a line that extends in a north and south direction through about the middle of Gray County, Texas, that portion of the field to the east of it being known as the East field and the balance of the field to the west of it being known as the West field. The black triangles on this map, being quite numerous near the oil zone, indicate carbon black plants. The black squares also in that territory and in other territory indicate the location of gasoline extraction plants. The large black solid dots indicate refineries and the small dots on the map the locations of wells.

Both the Texas Panhandle field in Texas and the Hugoton gas field in southwest Kansas and in the Oklahoma Panhandle, which lies just north of the Texas Panhandle field, are located in what is known as the High Plains Province. The controlling structural features of this whole area are what is known as the Amarillo Arch or buried Amarillo Mountains, the Ancestral Rockies, the Anadarko Basin, the Dalhart Basin and the West Texas Permian Basin.

The Amarillo Mountains consisted of a high granite range and it is believed that those mountains were formed in early Pennsylvanian time and extending from the present Wichita Mountains in Oklahoma some 150 miles northwest into Moore and Hartley Counties, Texas. It appears that this presently buried mountain range has been uplifted and submerged a number of times since its original formation. That is evidenced partly by the existence of granite wash on certain slopes of the buried range and evidences of weathering on some of the buried peaks. Apparently during a later period, in late Pennsylvanian time, limestone and shale and dolomite sediments were deposited over this submerged area. Subsequently to that, probably in Permian time, this buried range was covered with deposits of dolomites and anhydrites. Following the depositions, the depositing of the dolomite and anhydrite, which is known in this section as "Big Lime" series, apparently another uplift or partial uplift occurred, which caused faulting, folding and arching of these sedimentary beds. A portion of these sediments were at that time apparently eroded off after one of those uplifts, which is evidenced by the occurrence of pieces of anhydrite and dolomite embedded in the lower part of the so-called "Red Cave" section or series, or "Red Beds," and on the higher portion of these buried mountain peaks.

13 The arching of the Permian and Triassic beds into the anti-clinal fold, which is superimposed above the buried Amarillo Mountains, was brought about, evidently, partly by uplift in that range and partly by subsidence of the neighboring basins, that is, the Anadarko Basin to the north and east and the West Texas Permian Basin to the south.

The Anadarko Basin which lies to the north of the Amarillo Arch is known to contain carbonaceous formations. That was thought to be of an age corresponding to about Pennsylvanian time, and it appears that most of the productive oil pools in this portion of Texas are located on the flank of this Amarillo Arch nearest that basin. For that reason it is felt by many geologists and others that those carbonaceous sediment deposits in the Anadarko Basin are probably the source beds from which the oil and gas that is produced in this region originally came or was formed, and that that oil and gas subsequently migrated and was deposited in the basins formed by the porous

structures in the Amarillo Arch which now form the Texas Panhandle field.

It is interesting to note in this area the water level in the porous formations occurs very close to sea level. It is also interesting to note that the original and initial or virgin pressures in not only the Texas Panhandle field but in the Hugoton field were fairly uniform and were subnormal. The wells in these fields approximate 2600 feet in depth and a hydrostatic water head corresponding to wells of that depth would indicate the pressure should be around 1000 or 1100 pounds instead of 430, which was the initial pressure in this field.

In the Texas Panhandle field the basement rock consists of this granite peak of these buried Amarillo Mountains. At some portions of the slope of some of these peaks there occurs the granite wash I mentioned some time ago. It is a porous disintegrated granite. That granite wash overlies certain parts of those peaks, not all of them, and in certain parts of those areas of granite wash wells tapping it have produced oil and gas. However, the granite wash itself is not the principal producing horizon in this field. Overlying this granite wash, and in other places where the granite wash is absent, overlying directly the basement rock, is a series known as the Big Lime. This Big Lime series includes gray lime, gray dolomite and brown dolomite interbedded with what is known as anhydrite. That Big Lime series is the principal gas and oil producing formation in the field. The Big Lime is capped by beds of shale or dense limestone or impervious anhydrite, or all three. The dolomite, Big Lime and those other lime sediments are the porous structure in which the gas was trapped and that gas was kept in there by this overlapping, overlying impervious rock, cap rock.

Overlying the cap rock of the Big Lime in the order named occur a number of series that have been given the following names: Cave Series, Salt Series, Gypsum Series, and Sand Series, and between these various series there are interspersed beds of red clay known as the red beds. Above the last mentioned, from that point to the surface, occur beds of Permian, Cretaceous, Tertiary and Quarternary deposits, sand deposits, sediment deposits, sandstone and alluvium.

14 This field as it is presently outlined is somewhere around 124 miles long and averages about 20 miles in width. It extends, as shown on the map, in a northwest-

southeast direction and includes portions of Hartley, Moore, Potter, Hutchinson, Carson, Gray, Wheeler and Collingsworth Counties, in Texas.

The first gas well that was drilled in this field was completed in December of 1918 on what is known as the John Ray Dome in northern Potter County. In that well natural gas was encountered at 2605 feet and the shut-in wellhead pressure was 430 pounds.

The first oil well in the field was completed in May, 1921, by the Gulf Production Company, a well known as its Burnett well No. 2. That was completed in northern Carson County.

As of July 31, 1938, the field contained a total of 1498 gas wells and 3912 oil wells. The gas wells had a total daily potential open flow of 26,282,787 MCF of dry gas, and the potential oil production on that date was estimated to be 1,221,500 barrels of oil per day.

The Texas Railroad Commission estimates that the total dry gas acreage in this field includes 1,475,324 acres, of which 274,900 acres in the east field produce sweet gas, 801,400 acres in the west field produce sweet gas, and 398,900 odd acres in the west field produce sour gas.

The production of oil in the oil portion of this field is accompanied by the production of casinghead gas. This casinghead gas is sour gas and is used almost exclusively for the production of carbon black, being burned in the numerous carbon black plants located in the field.

The gas-oil ratio, or the ratio of the volume of casinghead gas produced with each barrel of oil, in this field is approximately 6 MCF. That is 6,000 cubic feet of gas produced with each barrel of oil.

The Railroad Commission of Texas estimates an ultimate probable recovery of oil of one billion barrels from this field. The production of oil to the end of July, 1938, was in excess of 318 million barrels.

The total withdrawals of dry and casinghead gas from this field through July 31, 1938, are estimated to be 6,939,957,820 MCF.

The present average daily production of dry and casinghead gas produced in this field approximates 1,520,000 MCF per day, and that production is segregated as follows: sweet dry gas, 640,000 MCF; sour dry gas, 540,000 MCF; casinghead gas, 340,000 MCF.

During the first seven months of 1938 the disposition of the gas produced in the field was as follows: for manufac-

ture of carbon black, 45%; sales to pipeline companies, 37.4%; gasoline plant, lease and other fuel, 11.6%; gasoline extraction loss, 3.7%, and blown to the air, 2.3%, making a total of 100%.

15 The total withdrawals of all gas from this field during the twelve months ending July 31, 1938, and I use that figure because some of the information and data that is involved in this hearing is completely available to that point, the total withdrawals from this field of all gas for the twelve months ending July 31, 1938, amounted to 577,579,759 MCF, of which approximately 216,000,000 MCF were taken by pipeline companies leading out of the field. Those pipeline companies consist of a number of companies, including Texoma and Natural Gas Pipeline Company, as well as the Canadian River and Colorado Interstate line to Denver and Cheyenne, the Northern Natural Gas Company line, which also taps the Hugoton field and extends to the Twin Cities in Minnesota, the Panhandle Eastern Pipeline Company line to Detroit, the Cities Service Gas Company line to Kansas City and other cities, the Lone Star Gas Company and Consolidated Gas Company, Empire Gas & Fuel Company, United Gas Pipeline Company, South Plains Gas Company, and other smaller ones.

I have estimated the original and remaining gas reserves in the Texas Panhandle oil and gas field, using in that estimate two methods: the method known as the reservoir-porosity method and the method known as the pressure-decline method.

Using an average thickness of pay of 70 feet and an average porosity of 20%, the per acre reservoir pore space or voids is estimated at 609,840 cubic feet per acre. The figure of 70 for thickness of pay and 20% average porosity has been used by Natural Gas Pipeline Company and Texoma or their representatives. Those figures are used generally in the Texas field—not exclusively, but they are largely used.

Using an initial virgin wellhead pressure of 430 pounds gauge and an average well depth of 2618 feet, the initial reservoir pressure was 471 pounds absolute. Upon this basis the per acre dry gas initially in place upon a pressure base of 16.4 pounds per square inch absolute was estimated to be 17,514 MCF per acre. Under each acre of productive land there is estimated to have been in place initially at

a pressure of 471 pounds absolute a total of 17,514 MCF of gas per acre.

Then, using a total productive dry gas acreage of 1,475,324 acres and a wellhead abandonment pressure of 25 pounds gauge at the wellhead, I estimated the initial volume of dry gas in place to be 23,645,017,700 MCF, and considering the same acreage in the same conditions but using instead of 25 pounds wellhead abandonment pressure a 100 pound abandonment pressure—that is, on a gauge basis at the wellhead, 100 pounds—I estimate the initial volume of dry gas in place to have been 19,255,928,800 MCF, both of these being on a pressure basis of 16.4 pounds absolute.

Those figures indicate an estimate of the dry gas under the dry gas acres and take nothing into account of the casinghead gas and in the oil area.

Using the Texas Railroad Commission's estimate of one billion barrels of oil, recoverable oil, and an average
16 gas-oil ratio of 6 MCF per barrel, I estimate that the total additional volume of casinghead gas in place was six billion MCF on a 16.4 pound absolute pressure basis.

The total withdrawals from this field on the same basis, that is, 16.4 pounds absolute, including both dry and casinghead gas, from the beginning of the field through July 31, 1938, is estimated to be 6,939,957,820 MCF. Deducting this amount of withdrawal from the original, rather, from the estimate of original dry and casinghead gas in place leaves a remaining total reserve of dry and casinghead gas on a 16.4 pounds absolute pressure basis of 22,705,059,900 MCF to a wellhead abandonment pressure of 25 pounds gauge, and 18,315,971,000 MCF to an abandonment pressure of 100 pounds gauge.

At the 1938 rate of withdrawal of gas from this field, including both dry and casinghead, on a pressure basis of 16.4 pounds absolute, which was 577,579,759 MCF, the estimated remaining reserve of dry and casinghead gas in this field would last 39.3 years to a wellhead abandonment pressure of 25 pounds, and 31.7 years to an abandonment wellhead pressure of 100 pounds gauge.

By the expression "1938 rate of withdrawal" I had in mind the twelve months period ending July 31, 1938.

My calculations and conclusions under the pressure decline method were arrived at in the following way:

Again using an initial virgin wellhead pressure of 430 pounds gauge and an initial reservoir pressure of 471

pounds absolute, and the Texas Railroad Commission's weighted average, so-called, wellhead pressure of 337.66 pounds gauge, determined by that Commission as of July 31, 1938, the weighted average reservoir pressure on that date would be 373 pounds absolute. The difference between 373 pounds absolute and the initial reservoir pressure of 471 pounds absolute represents a drop in reservoir pressure from the beginning of the production in that field up and through July 31, 1938, of 98 pounds absolute average.

The total dry gas withdrawals through July 31, 1938, were 5,031,957,820 MCF on a 16.4 pounds pressure basis, that is, absolute pressure, which represents an average of 51,346,508 MCF of dry gas produced per pound of reservoir pressure drop.

Using a wellhead abandonment pressure of 25 pounds gauge, which corresponds to a reservoir pressure of 40 pounds absolute, or an ultimate pressure drop in the reservoir of 431 pounds, that being the difference between the reservoir absolute pressure at time of abandonment and the reservoir absolute pressure initially, gives an initial volume of dry gas in place to an abandonment pressure of 25 pounds gauge at the wellhead of 22,130,344,900 MCF on a 16.4 pound absolute pressure basis.

Then, using an abandonment wellhead basis of 100 pounds gauge, which corresponds to a reservoir pressure of 120 pounds absolute, or an ultimate pressure drop in
17 the reservoir of 351 pounds, gives a calculated initial volume of dry gas in place to an abandonment pressure of 100 pounds at the wellhead of 18,022,624,300 MCF on a 16.4 pound absolute pressure basis.

Then, again including the six billion MCF of original casinghead gas in place, and total dry and casinghead withdrawals the same as before of 6,939,957,820 MCF, the total estimated remaining reserves of both dry and casinghead to a wellhead abandonment pressure of 25 pounds gauge at the wellhead is estimated to be 21,190,387,100 MCF, and to an abandonment pressure of 100 pounds at the wellhead, 17,082,666,500 MCF, both on a 16.4 pound absolute pressure basis. At the 1938 rate of withdrawals, and there I mean the twelve months ending July 31, 1938, namely, 577,579,759 MCF, these remaining reserves would last, according to this method of calculation, for 36.7 years to an abandonment pressure of 25 pounds gauge, and 29.6 years to an abandonment pressure of 100 pounds gauge at the wellhead.

(Map entitled "Texas Panhandle Gas Fields" showing Texoma Natural Gas Company leases as of January 1, 1939, marked Exhibit 13 for identification.)

Exhibit 13, obtained by me from Mr. Dickinson, of Texoma, at Amarillo, Texas, is a map which shows again by a black line the outside boundaries of the Texas Panhandle oil and gas field. It also shows by a red line extending from a point south of Pampa in Gray County and extending in an irregular northwest direction up to the point near the west boundary of the field and cutting down to the southwest corner of the field in Hartley County, the sour gas line, so-called, or the line which purports to divide the sour gas area from the sweet gas area, the sweet gas area being south of the line and the sour gas area being north of the same line.

It also shows colored in yellow the leases of Texoma as of January 1, 1939. Those leases are somewhat scattered over the entire portion of the field, including the portion of the east field and portion of the west field, these leases largely lying in the so-called sweet gas area.

The total gas acreage of Texoma, as colored in yellow on this map, is 153,795.14 acres. It is my estimate that the initial natural gas reserves in this acreage, calculated on a 16.4 pound absolute pressure base to a wellhead abandonment pressure of 25 pounds gauge, were 2,464,872,465 MCF, and on the same pressure basis to a wellhead abandonment pressure of 100 pounds it was 2,007,332,340 MCF.

The total natural gas withdrawals from this acreage through December 31, 1938, were, on a 16.4 pound absolute pressure basis, 281,954,457 MCF. This information was obtained by me from Mr. W. F. Martin, through Mr. C. J. Peterson, both of Texoma.

The withdrawals during the year 1938 were 52,663,513 MCF on a 16.4 pound absolute pressure base. At that rate of withdrawal, the remaining reserves of Texoma as I have estimated them would last 41.45 years beyond December 31, 1938, to a wellhead abandonment pressure of 25 pounds gauge, and 32.76 years to a wellhead abandonment pressure of 100 pounds gauge.

18 Using the reservoir-porosity method, I have recently made an estimate of the initial and remaining gas reserves of the Hugoton gas field. Using an average thickness of pay in the Hugoton field of 45 feet and an average porosity of 15%, average well depth of 2600 feet, and a productive acreage of 2,200,000 acres, with an initial

wellhead pressure of 435 pounds gauge, I estimate the initial volume of natural gas in the Hugoton field, on a 16.4 pound absolute pressure base, to have been as follows: at a wellhead abandonment pressure of 25 pounds gauge, 17.3659 billion MCF; to a wellhead abandonment pressure of 100 pounds gauge, 14.1437 billion MCF.

The total natural gas withdrawals from the Hugoton field through December 31, 1938, was 153.5 million MCF. This left remaining reserves as of December 31, 1938, of 17.2124 billion MCF on a 25 pound abandonment pressure, or 13.9902 billion MCF on a 100 pound abandonment pressure. The 1938 rate of withdrawal was 29.494 million MCF. At that rate of withdrawal, the field would last from December 31, 1938, under present conditions, that is, the conditions obtaining during the year 1938, with the present pipelines as they are, approximately 583 years to a 25 pound abandonment pressure, or about 474 years to a 100 pound abandonment pressure. The amount of gas being taken out of there as compared to the reserve is very small.

The Natural Gas Pipeline Company line runs to the southeast of the Hugoton field and approaches the generally accepted border of that field within ten or eleven miles. However, it is about 36 or 38 miles, probably, from the center of that field as it exists today to the company line.

I believe 25 pounds is a reasonable figure to use as the abandonment pressure in connection with an estimate of reserves in the Texas Panhandle field. It is a figure that is used by the Cities Service Company and the Lone Star Gas Company. It is a figure used by the Texas Railroad Commission in its calculations, and Hagy, Harrington & Marsh have used it in a case before this Commission. The Panhandle Eastern Pipeline uses 30 pounds in their estimates. Northern Natural uses 50 pounds. I believe 25 pounds gauge at the wellhead is a reasonable figure to use because I know of no definite reasons why gas should not be removed from those formations down to at least 25 pounds. I understand there is at least one company that is contemplating putting a vacuum on its well.

By that statement I mean that as long as a well has pressure in it sufficient to force gas from the formations into the well bore and up and out through the casinghead of the well and into the gathering lines of a system the well flows. As the pressure in the sand falls, the pressure in the reservoir is depleted or decreased and is reduced. Of course, the pressure available at the wellhead is reduced and the well

will flow only to a certain point. However, it is common practice in some fields in this country and in other countries to carry the production of gas on down beyond the point where it would normally flow of its own pressure and to withdraw the gas from the formation by suction or vacuum.

19 A map has been prepared under my direction, showing the location of the Texas Panhandle and Hugoton fields with relation to the line of Texoma Natural Gas Company and Natural Gas Pipeline Company of America.

(Map entitled "Natural Gas Transmission Lines of (A) Texoma Natural Gas Company, (B) Natural Gas Pipeline Company of America, (C) Chicago District Pipeline Company" marked Exhibit No. 14 for identification.)

(May 9, 1939.)

Exhibit No. 14 shows the 24-inch transmission line of Texoma Natural Gas Company and Natural Gas Pipeline Company of America originating in the Texas Panhandle field, passing within approximately ten miles of the eastern boundary of the Hugoton field in Hansford County, Texas, and approximately thirty-six miles from the center of the Hugoton field in Stevens County, Kansas. The map also shows delivery points of gas which is delivered from this line.

(EXHIBITS NOS. 1 to 14, inclusive, for identification, offered and received in evidence without objection.)

Response of Natural Gas Pipeline Company of America and response of Texoma Natural Gas Company to the Federal Power Commission's Order No. 51 filed with said Commission on August 15, 1938, incorporated in the record by reference without objection.)

20 JOHN M. WOODFORD testified on behalf of the Illinois Commerce Commission as follows:

Direct Examination by Mr. Booth.

(May 9, 1939.)

My name is John M. Woodford. I live at 4715 Malden Street, Chicago, Illinois. I am an accountant with the Illinois Commerce Commission and have been in the employ of that Commission since May, 1934.

In 1913 I graduated from St. Bonaventure's College, St.

Johns, Newfoundland, and at the outbreak of the World War I enlisted with the Canadian Expeditionary Force in 1914, until my discharge in 1919.

From May, 1920, to May, 1921, I did general accounting work with Prest-O-Lite Company, Inc., New York City.

From June, 1921, to April, 1923, I worked on the accounting staff of Deloitte, Plender, Griffiths & Company, of Havana, Cuba, my work covering audits of sugar mills, insurance companies and public utilities.

From April, 1923, to April, 1925, I was traveling auditor for Electric Bond & Share Company, 2 Rector Street, New York City. My work there covered prepurchase investigations, installation of accounting systems, and audits of their domestic and foreign properties.

From April, 1925, to April, 1927, I was employed by National Public Service Corporation as accountant in charge of financial statements, investigations, consolidated statements and preparation of statements in connection with merger possibilities. I also worked on prepurchase investigations and closings of such purchases.

From April, 1927, to June, 1931, I was treasurer of Standard Public Service Company, which company owned and operated numerous water and telephone utilities in about one hundred communities.

From June, 1931, to May, 1934, I was employed for the most part on special investigations and audits with such companies as American Equities Reporting Company and Barrow, Wade, Guthrie & Company, public accountants and auditors, both firms being in New York City.

I joined the staff of the Illinois Commerce Commission in May, 1934, and have been working under Mr. Fred Kleinman, chief accountant, as accountant in charge of field work. I was in charge of the field work in the examination of the books and records of Commonwealth Edison Company, Illinois Bell Telephone Company, Peoples Gas Light & Coke Company, Chicago District Pipeline Company, all in the State of Illinois, and all of which work was in connection with rate cases for the Illinois Commerce Commission. I also worked on numerous other utilities throughout the State of Illinois.

I made an investigation of the books and records of Natural Gas Pipeline Company of America and Texoma Natural Gas Company for the purpose of determining the income and expenses of those companies per books by

21 calendar years from the commencement of operations of these companies to and including December 31, 1938. For the year 1938 our work has not been fully completed; but we have sufficient information to determine the net earnings of the company for the year 1938 as per the books.

(Document entitled "Natural Gas Pipeline Company of America and Texoma Natural Gas Company, Earnings Statements Per Books Calendar Years from Commencement of Operations to December 31, 1938," marked Exhibit 15 for identification.)

Exhibit 15 reflects the results of our investigation. This exhibit may be divided into three parts. Pages 1 to 7, inclusive, cover the operations of Natural Gas Pipeline Company. Pages 8 to 15, inclusive, cover the operations of Texoma. Pages 16 and 17 show the combined operations of both companies, merely eliminating from such combination intercompany transactions.

Both companies close out their accounts reflecting income and expenses each month to an account called "Profit and Loss," summarizing the result of the month's business in a statement called "Monthly Financial Statement." These monthly financial statements also show cumulative totals for the calendar years to date. The figures shown for the different years in the exhibit are the cumulative totals as shown on the monthly financial statements for the month of December of each year. These cumulative figures were checked against the figures as recorded on the books and are in agreement.

In all of the statements in the exehibit the first column of figures is the cumulative totals, and I believe is No. 1. Column A is for the period from October 15 to December 31, 1931, when the company started operations. October 15 is when the company started operations. The other columns B to H are for the respective calendar years of 1932, 1933, 1934, 1935, 1936, 1937, and 1938.

Page 1 of the exhibit is an earnings statement for Natural Gas Pipeline Company in condensed form. This is the final statement for this company. The other statements, pages 2 to 7, inclusive, are merely supporting schedules.

Page 2 of the exhibit presents on lines 3 to 9 a breakdown of the amounts included by the company in gross earnings from operations, shown on line 3 of page 1, in the amount of $75,312,431.94.

Lines 12 to 22 of page 2 represent the amount included

by the company in operations and maintenance expense as shown in line 4 on page 1 in the amount of $39,891,416.91.

The lower half of page 2, lines 25 to 41, shows certain data as to the volumes of gas stated in MCF involved in the company's operations. Line 27 shows the volumes of gas at 16.4 pounds pressure basis and line 30 represents the same quantities of gas converted to a 14.65 pound pressure basis, which is the selling basis of Natural Gas Pipeline Company and on which basis lines 32 to 41 are stated.

Page 3 presents a further breakdown of the sales of gas as shown in the total amount of $75,312,810.93 as shown in line 6 on page 2. In particular it shows the sales to the Chicago District Pipeline Company under existing contractual classifications in quantities stated in MCF, included in lines 2 to 12 inclusive, and the revenues derived from such sales in dollars are shown on lines 16 to 30, inclusive. There is a difference of 51,390 MCF in total gas sales to Chicago District Pipeline Company between the figures on page 3 and page 2. This difference appears in the company's monthly financial statement for the 1931 period and we have taken the figures as therein stated. Sales to others are shown separately in detail on page 5 of the company's monthly financial statements but have been consolidated into totals on page 3 of this exhibit, line 13, for volumes of gas in MCF, and in lines 32 to 36 for dollars.

Page 4 is entitled "Other Operating Income and Non-Operating Income." Lines 4 to 6 give the breakdown. The other operating income is shown in line 8 on page 4 in the amount of $274.92. On lines 12 to 18 there is given a breakdown of non-operating income, shown on line 6 of page 1, in the amount of $10,385,877.40.

Page 5 is entitled "Purchased Gas and Gas Used by the Company." Lines 3 to 14 present the details of the volume of gas purchased, shown on line 27, page 2, 350,997,237 MCF.

The next block of lines, 18 to 27, present the details of the cost of gas purchased, shown on line 12 of page 2, in the amount of $27,055,136.38. The last two lines, 30 to 32, present the quantity and dollar value of the gas used by the company in its operations.

The statements presented on pages 1 to 5 were taken, as before stated, from the company's monthly financial statements and agree with the books as recorded in the income

accounts. However, adjustments are recorded on the books of the company which apply to the figures presented on page 1. These adjustments are summarized on page 6 of this exhibit entitled "Adjustments to Income Accounts."

In lines 2 to 23 of page 6 we present the net effect of all adjustments on the company's books which were made to surplus. In lines 25 to 33 we present the effect of adjustments which were recorded in the company's journal, but which were not reflected on the company's general ledgers. These adjustments were made in 1934 to record offsetting transfers between the years 1932 and 1933. While these adjustments change the profit as recorded on the statements for 1932 and 1933, they do not affect the total profit for the period. In lines 36 to 41 we present adjustments reflected in the fixed capital account No. 1019, entitled
23 "Preliminary Operations." This arises out of the fact that for the period ended December 31, 1931, the company showed on its books a profit of $671,061.71 from its operations. In 1933 this amount was transferred to Account No. 1019, Preliminary Operations, reducing the recorded cost of the fixed capital by that amount. In 1934 certain adjustments were made to Account No. 1019, Preliminary Operations, the largest item being a charge for interest on notes for the period ended December 31, 1931, in the amount of $752,136.16. This item along with other adjustments changed the profit of $671,061.71 into a loss of $7,996.92, which amount consequently becomes an addition to the cost of fixed capital. The last line, line 43, presents the net adjustments applicable to the amounts transferred to profit and loss for each year, which are shown on line 22 of page 1 of this exhibit.

On page 7 we present the company's surplus account in two ways. Lines 2 to 13 present it as recorded on the books of the company. Line 2 presents the balance transferred from the profit and loss accounts and these are the amounts shown on line 22 of page 1. Line 7 presents the net effect of the adjustments made on the books related to the year in which made. On the other hand, lines 16 to 27 present the surplus account giving effect to the adjustments in the years to which they apply instead of the year in which they were made. Line 9 and line 24 is the income for the 1931 period transferred to Account 1019, Preliminary Operations, discussed above, and the amount on line 24, a loss of $7,996.92, is the balance as of December 31, 1938, in this sub-account of the property account. It will be noted that

the final figure for surplus at the end of 1938 is the same in line 27 as in line 13, the amount of $918,791.50. The difference between the two sections of this table arises from transferring amounts from the year in which they were recorded to the year to which applicable and does not involve any change whatever in the surplus at the end of the period.

This ends the explanation of the statement covering pages 1 to 7. These cover the Natural Gas Pipeline Company of America.

The second part of the exhibit, being pages 8 to 15, deals with Texoma Natural Gas Company.

Page 8 is an earnings statement of Texoma Natural Gas Company in condensed form. The other pages, 9 to 15, inclusive, are supporting schedules.

On page 9 of the exhibit, entitled "Gross Earnings from Operations—Natural Gas Division and Gasoline Division and Non-Operating Income," lines 2 to 21 are a breakdown of the gross earnings from operation of the Natural Gas Division shown on line 4 of page 8, in the amount of $21,694,333.79.

Lines 24 to 31 are a breakdown of gross earnings from operations in the gasoline division shown on line 5 of page 8 in the amount of $3,315,513.07.

The third section, lines 36 to 40, is a breakdown of
24 non-operating income, shown on line 20 of page 8, in the amount of $112,643.06.

Pages 10 is entitled "Earnings analysis, gas sales statistics." This shows in volume the sales of gas by Texoma during the period and the customers to whom the sales were made. It also shows the quantity of gasoline sold in each year.

Page 11 is a statistical table of the quantities of gas and gasoline involved in the companies' operations. It shows the various sources from which the gas was received and the disposition thereof, and also the net production and purchases of gasoline and the disposition thereof.

Page 12, entitled "Operation and Maintenance Expense, Natural Gas Division," presents a breakdown of the operation and maintenance expense of the natural gas division, as shown on line 10 of page 8, in the amount of $5,292,972.81.

Page 13 is a breakdown of the operation and maintenance expense of the gasoline division, as shown on line 11 of page 8, in the amount of $935,240.95.

The statements presented on pages 8 to 13 were taken, as before stated, from the company's monthly financial statements, and agree with the books as recorded in the income accounts.

However, adjustments are recorded on the books of the company which apply to the figures presented on page 8. These adjustments are summarized on page 14, entitled "Adjustments to Income Account."

On lines 2 to 16 of page 14, we present the net effect of all adjustments on the company's books which were made to the surplus account. On lines 18 to 30 we present the effect of adjustments which are recorded in the company's journal, but which are not reflected on the company's general ledger.

These adjustments were made in 1934, and record offsetting transfers between the years 1932 and 1933, and change the profit as recorded on the statements for the years 1932 and 1933, but they do not affect the total profit for the period.

On lines 33 to 41 we present adjustments which are not recorded on the books of Texoma but they are recorded on the books of Natural Gas Pipeline Company, in so far as they affect the purchased gas account of the Pipeline Company. They are reflected here because they arise out of adjustments to Texoma accounts, although the net effect on profit on the books of Texoma is zero.

Page 15 is a surplus account of Texoma presented in two ways. Lines 2 to 7 present it as recorded on the books of the company. Lines 10 to 16 present the surplus, taking all the adjustments from the years in which they were recorded and transferring them to the years to which they apply. It will be noted that the surplus at the end of the period, December 31, 1938, in both sections of the statement are the same, in the amount of $1,852,799.50.

Page 16, entitled "Combined surplus-net profits, Natural Gas Pipeline Company of America and Texoma Natural Gas Company," shows in combined form the surplus net profits; that is, the net profits after applying all surplus adjustments for both companies, and after eliminating offsetting inter-company transactions, consisting of purchases and sales of gas, and interest payments and receipts.

Included with the elimination of purchases and sales of gas is an amount paid Colorado Interstate Gas Company

by the Natural Gas Pipeline Company of America, and received by Texoma Natural Gas Company from Canadian River Gas Company for leased facilities.

Line 23 shows the net earnings from operations of the combined companies before depreciation, depletion and retirements. The amount for the period is $54,110,738.66. This is the same amount which appears as the final figure on page 17, line 20.

Page 16 is subject to the footnotes as shown on page 16-A.

Page 17 shows for each company separately and for the two companies combined the net earnings from operations before depreciation, depletion and retirements per books after reflecting in the years to which applicable all adjustments affecting income recorded on the books of both companies.

Page 18 shows in condensed form the amount of moneys expended by Natural Gas Pipeline Company of America in connection with regulatory matters, and is included by the company in its general and miscellaneous expenses in an account entitled "Regulatory Commission Expense."

(EXHIBIT 15 for identification, offered and received in evidence without objection.)

Examiner Durrance: As I understand, you reserve the privilege of cross-examining the witnesses?

Mr. Morgan: Yes. With the Examiner's permission, we would like to have these figures checked by our accounting department. After that we would like the privilege of cross-examining the witness. He is right here in town and can be cross-examined at any time.

With reference to further proceedings, my suggestion, Mr. Examiner, is that we recess until the 22nd. That will enable us to get our geologists and other people up here from Texas to prepare for the cross-examination of Mr. Brown; and will enable us at the same time to go on with our preparation of our own testimony which, by that time, we ought to have in form to put on to a substantial extent. I think the cross-examination of Mr. Brown and the other testimony we will have ready at that time will consume a couple of weeks.

25-A Examiner Durrance: Is there any objection to the motion presented by Mr. Morgan?

Mr. Booth: We have some additional testimony that is not quite ready. We would have it ready perhaps by the first part of the week, but if the case is going over for

cross-examination and for the presentation of testimony on behalf of the company, we would be satisfied to have the case go over to the 22nd, at which time we could present the additional testimony which we will have, which will then take only half a day or a day.

I say that with the understanding, however, that the company will proceed with both its cross-examination and presenting a substantial part of its case.

There is one further thing that would aid us materially in expediting the cross-examination of the company's witnesses; and that is if the company could conveniently furnish us with several copies of its exhibits, because there will be several of our people who will be working on their exhibits; and it would be a great convenience to us if the company can furnish us with several copies of their exhibits. We have furnished them today, whether they insist on having them or not, extra copies, ten extra copies of the exhibits that we have submitted in evidence this morning.

Examiner Durrance: What is the position of Commission's counsel with reference to the motion?

Mr. May: Mr. Examiner, in view of the statements made by Mr. Morgan and Mr. Booth, it is the opinion of Commission's counsel that in the interest of overall expedition of the proceedings, it probably would be desirable to adjourn the hearing to May 22nd, or to such convenient date as may be determined by the Examiner.

Examiner Durrance: The Examiner understands then, in the event we take a recess until an agreed date, we will reconvene for the purpose of allowing defendants' counsel the privilege of cross-examining the witnesses who have been presented at this hearing; and in addition thereto putting on your affirmative evidence; is that correct?

Mr. Morgan: We intend to do that and go as far as we can at the next session, yes, sir. It is my present thought, with what Mr. Booth has offered, and the cross-examination of these witnesses, that we will consume a couple of weeks, which the Examiner has stated he desires to spend here at that time.

Examiner Durrance: With that understanding, the hearing will be adjourned, to be reconvened on Monday, May 22, 1939, at 10 o'clock A. M., in this room.

Examiner Simpson: * * * It is the Examiner's understanding that counsel for the Natural Gas Company and Texoma is now prepared to cross-examine the previous wit-

nesses and in addition thereto will also put on affirmative evidence. Is that true, Mr. Morgan?

25-B Mr. Morgan: That is true. We are not ready to put it all on. However, we have evidence ready that will take several days.

Examiner Simpson: It is understood the temporary adjustment in the order of presenting witnesses in nowise affects the Commission's designation that the defendants-respondents shall open and close * * *.)

26 CLAUDE C. BROWN further testified on behalf of the Federal Power Commission as follows:

Cross-Examination by Mr. Morgan.

(May 22, 1939.)

I testified that from 1904 to 1922 I held various engineering positions with certain companies named and enumerated the Pacific Light & Power Company and others.

The Pacific Light & Power Company was an electric generating and distributing company in Los Angeles. The Lewellyn Iron Works and the Baker Iron Works were iron works just as the name implies. The Southern California Edison Company was an electric utility. The Southern Pacific Railroad Company was engaged in railroad operation. The J. G. White Engineering Corporation was an engineering firm engaged at the time I was with them in valuations of various gas and electric utilities. That was artificial gas in those days. The Northern California Power Company was an electric company. The Pacific Gas & Electric Company was a gas and electric company (artificial gas, manufactured gas, at that time).

In 1917 I entered the army, and in November 1922 I became connected with the California Railroad Commission in the capacity of assistant valuation engineer engaged in the appraisal of various gas and electric utilities. Those were both natural gas utilities and artificial gas utilities, but mostly natural. My position was state-wide, and my duties carried me all over the State, but the headquarters of the California Railroad Commission were in San Francisco. I lived in San Francisco during a part of the time, but moved to Los Angeles in 1923 and lived there until about the beginning of 1930. The Railroad Commission of

California has a branch office in Los Angeles, but their main office is in San Francisco.

During the period from 1923 to 1930 I was working out of Los Angeles, but my duties took me all over the State. I occupied the position of assistant engineer in the gas and electric division, performing engineering and rate work in connection with natural gas, manufactured gas and electric matters, and in 1926 became gas engineer. In the latter position the duties involved were almost exclusively gas matters, being largely natural gas matters, but including also what manufactured gas matters came before the Commission at that time.

I finally became chief engineer of the California Railroad Commission in 1933. That position covered the whole field of the Railroad Commission's activities, including all engineering matters that came before the Commission involving gas, electricity, water, telephone and transportation. In other words, that position was the head of the engineering department of the Commission.

27 I was retained by the Texas Company as one of a number of consulting engineers to pass on reserves in the Kettleman Hills field. The Texas Company was in litigation with some other company involving the value of certain holdings they had in the Kettleman Hills area, and the purpose of the investigation was to determine ultimately the valuation of those properties, including gas and oil. This was around 1929 or 1930. I was employed at the same time by the California Railroad Commission.

My particular duties in connection with that appraisal were a determination of the reserves and the markets for natural gas in California. I worked with other engineers, including Professor Uren. In connection with that work plans were made to go ahead with the determination of the reserves of that company and the valuation thereof, but before these matters were consummated the matter was settled.

The Butte Oil Fields, Incorporated, are oil operators in Sutter County, California; but they handle some natural gas. They have leases on some 40,000 acres around what is known as the Buttes in Sutter County, in northern California. The work I did for them was testing wells, gas wells, and estimating the amount of reserves they had in that area. That information was used in the consummation of a contract with Pacific Gas & Electric Company to sell gas to the latter for distribution in northern Califor-

nia. This was in 1938 and at that time I was with the California Railroad Commission. At that time I was testing the potentials to see what the productivity of the wells was, and estimating the reserves. I based the estimates partly on the potentials. Four gas wells were involved in that matter, all on one tract of 40,000 acres.

I have been in Texas several times during the last ten years or so. I have been through Oklahoma but have never done any work there. When I was in the Texas Panhandle recently, in Amarillo, in March, I was there about a week. I stayed in the State about a week, most of the time being spent in the Panhandle field in and around Amarillo and between it and the Hugoton field. While in Amarillo I went to see Mr. Dickinson, Mr. Martin and Mr. Peterson, of the Texoma office there. I may have met others in that office that I did not note. I did talk to Mr. Williams, in charge of the Texoma pipelines, and Mr. Powers, of the compressor station at Fritch.

I also talked to Mr. Ford of the Canadian River Company and Mr. Waltin of the Republic Natural Gas Company at Hugoton. I was in Hugoton part of one day. I also talked to Mr. Batten, in charge of the Pampa station of Cities Service Gas Company. My purpose in talking to Mr. Ford and Mr. Batten was that I was going over the area in the field and desired to visit these various compressor plants and areas and in visiting them I contacted these people because I was desirous of securing information on the Canadian River properties. We have a case or investigation pending involving the Canadian River properties and also a complaint filed against the Cities Service.

I also talked to Messrs. Harrington and Marsh, of Amarillo, about three or four hours. To my knowledge, they are not interested in this matter in any way; but they were interested in a case we had before us at that
28 time involving a certificate, the building of a line by Kansas Pipeline & Gas Company from the Hugoton field to Minnesota. I was discussing it with them, and the general condition of the field and their holdings in the Hugoton field and the Texas field. That application is one for a pipeline out of Hugoton, but they do have acreage in the Texas Panhandle.

I went on a trip with Mr. Dickinson and we visited the Fritch station and necessarily went over some of the properties of the company on our way—some of the leases. We

didn't make any effort to go to each producing well. We went past a number of them. They were pointed out to me and we just drove by.

I have never seen a gas well drilled in the Panhandle or personally made any microscopic examinations of the producing formations. I have seen samples of the formations but have never analyzed them myself. I have examined to some extent logs of wells in the Pnhandle. I examined logs of some of the wells of the Canadian River Company. I looked over analyses of the well data involved in those logs. I also had a long discussion with Mr. Peterson in which we looked over the records, samples, etc.

While in the Fritch station I examined the plant as to design and as to the machinery in use there. I examined the gasoline plant and the dehydrating plant. I observed the pressure at which the gas was being handled at the Fritch, compressor station. It was coming in from one of the lines at 180 pounds, and from the other two, as I remember it, at approximately 220 pounds. I would say that it was a specially designed arrangement, a very large compressor plant, and the gasoline extraction plant and dehydrating plant and so forth all tied in for unit operation. I would say that it was specially designed to meet the requirements of this company. The engines used there were larger than those in common use. The compressors were horizontal direct connected gas engine driven Worthington compressors of about 1250 horsepower capacity. It is my information that they were specially built for this 24-inch pipeline and the plant which handles the gas through that pipeline. We had quite a bit of discussion at the time I visited that plant, a rather interesting discussion with Mr. T. E. Powers.

Mr. Powers informed me at the time as to the history of the plant—that those engines were built especially for that plant. At the time they were built I believe he stated they were probably the largest units of the type that Worthington had built; also, the compressor, that is, the discharge compressor, was rather large as compared to many of the other plants in the country and that they were having trouble down there with those engines to some extent. I noted a number of cylinder heads outside along the wall of the plant there that had gone bad and also a section of one of the pistons from one of the engines that had snapped off. I understood from talking with Mr. Powers that Texoma was working with Worthington in an endeavor to

develop an engine that would carry that load and those pressures.

29 It is my understanding that it was a matter that had to be developed especially for a station such as that of Texoma. There are other lines that are as large as 24 inches. There are other lines that are larger than that. There is a 26-inch line of Standard Oil Company in California which is about 200 miles long. The Northern Natural Gas Company has a 24-inch line. That line secures gas from the Texas Panhandle and also from the Hugoton field. It extends from there north to the Twin Cities, St. Paul and Minneapolis. I think that is the only 24-inch line coming out of there. The Panhandle Eastern is 22-inch; the Canadian River is 22-inch; the Cities Service is 20-inch; and the United Gas Pipeline Company's line is 16-inch. These are the only lines I have in mind as large as that of Texoma and Natural Gas Pipeline Company.

As to whether until I ran into this Panhandle pipeline I had ever heard of a pipeline transporting gas 900 miles to market, of course I knew of this line. I knew of the Northern Natural pipeline and of the Denver line; but the Denver line isn't as long.

There is a difference in the practical economics of operating a line over a distance of 900 miles and over a distance of two or three hundred miles. The principal economic difficulty confronting a line running over such a long distance as that is that in the first place a long line of this kind is apt to cross a number of rivers. There are always operating problems both as to initial design and as to the maintenance of service on a line that has river crossings on it. There is always a potential hazard that the line will go out under some extraordinary conditions.

Other things that affect the economic operation of the line are pressures. A long line such as the one we are talking about, carrying a substantial load, must be equipped and furnished with booster stations or compressor stations along the line to maintain the pressure. (Objection by commission counsel.) You can't carry as much gas through a line at 100 pounds pressure as you can at 200 pounds, and you can't put as much through at 400 as you can at 700. The ordinary pressures at which pipelines were operated in 1928 or 1930 were around 300 or 400 pounds. It was an unheard of thing in the natural gas business to transport gas under pressure of 700 pounds until about that time—it had not been done.

Generally speaking, the pipe that was used in those days was not adequate to maintain pressures of that character. The pipe that was laid at that time and prior to that time was not really designed to carry pressures higher than those commonly in use, namely, 300 or 400 pounds. Many of the lines had Dresser couplings, and the couplings themselves and the weights of the pipe were chosen to take care of those lower pressures.

I think there are nine compressor stations along the line beginning at Fritch and on to Joliet, or rather, there are nine belonging to the Pipeline Company and one to Texoma, making ten in all.

The town of Fritch is located approximately near the southwest corner of Hutchinson County. That is where that compressor station is located. At this station one of the lines was bringing in gas at a discharge pressure of 180 pounds when I visited it. From my knowledge of the gas business, I would say that the prevailing pressure out in the line where the gas was coming into the line would have to be higher than 180 pounds because otherwise gas would not flow to the compressor station. It is the difference in pressure that causes gas to flow from one place to another. The gas flows from high pressure to low pressure exactly as water flows from a higher level to a lower level. If the pressure of the wells now discharging gas into the line gets down to 180 pounds, then the gas coming to the compressor station will be at a correspondingly lower pressure. It will then be necessary to raise that pressure to whatever pressure the gas is delivered from Fritch.

In other words, I would say this, if and when the gas pressure at the wellhead reduces and goes down, which it will, as that reduces, then the delivery pressure in the gathering system of the Texoma Company will be correspondingly reduced so that the gas gathered from those wells will be less in pressure at the time of delivery through the gathering system to the compressor station inlet.

It will be less in volume measured at 16.4 pounds per square inch when the discharge pressure is reduced, if you assume you drill no more wells. In other words, if the wells you are now pulling there constitute all at that time, and they are just let go ahead and produce, then the wellhead pressure will reduce the quantity, volume and pressure of gas delivered to Fritch from your delivering system. When the pressure in the field gets down to where it

is the same as the intake or discharge pressure at the compressor station, then the volume of gas coming in there will be greatly reduced below what it is now from the individual wells, unless you want to drill additional wells and produce more gas. As a practical matter, it is inevitable that other wells will have to be drilled to keep up that volume.

It is commonly observed to be the fact that the open flow of the wells in the Panhandle field decreases at a more rapid rate than the wellhead shut-in pressure. This is due, I believe, to the character of the producing formation, there being a rather dense dolomitic formation.

Even if you have gathering lines enough to bring sufficient gas into the Fritch station at a lower pressure than that at which it is coming in now, you would have to add to your compressor station equipment in order to build the pressure up from a lower level to the level at which it is going out of Fritch. As to whether you could do it with the same machinery used in building the pressure from 180 or 220 pounds up to the discharge pressure would depend, of course, on the load. I presume if you increase the load there would be no question about it. The day I was there I think the station was handling approximately 230 million cubic feet per day. Whether or not that is the full capacity of that station, I don't know. I do know that out of fifteen compressors, fourteen were on the line. I presume it was pretty well loaded up.

31 As to building up the pressure in the field with the intake at the Fritch station remaining substantially what it is now, after the pressure of the wells goes down to 180 or the intake pressure at the gathering line goes down to 180, it will be necessary, of course, to maintain that quantity of gas, and as the wells become depleted, to secure additional gas—drill other wells or do something to the wells you have. One possibility is the treatment by acid. In the Panhandle field it has been done. Wells have been treated with acid to increase their open flow. The effect of that treatment and the method of that treatment is the introduction of certain quantities of hydrochloric acid into the wells and into the formation. That acid eats or dissolves this limestone or part of it around the well bore, thereby increasing the size of the bore, increasing the channels, the area of the channels, by which gas is taken from the formation into the well bore. That is one method.

As to whether it adds any gas to the area or simply

creates a bigger bore at the bottom of the well and temporarily stimulates the potential, what it does is to increase the open flow due to the fact that it creates a larger area from which the gas can get into that well bore. It does not, of course, affect the total initial gas or the total remaining gas in reserve but it does act to allow that gas that is there to get to the well and come out. It would probably add something to the flowing pressure, for how long is undetermined. My information is that tests have been made there, wells have been treated, and after a year's time it was noted that this increased flow had continued. How long that would continue I don't know.

You inquire whether this means that the increased pressure is built up as a result of acidization and that this has been maintained over a period of a year. I do not wish to be misunderstood. I am not speaking of the static pressure, the formation pressure; I am speaking of the motivating force that forces the gas out of the formation and up through the casing. That motivating force comes from the reservoir.

You affect the reservoir pressure by the acidization. You don't increase the static pressure or the pressure in the sand but you do affect the pressure as to its effectiveness at the shoe of the well, the bottom of the bore. What is done is this: You have a reservoir of rather dense limestone. There is quite a resistance to gas passing through that porous medium. If you do anything to reduce that resistance, reduce that resistance of flow—friction, then you get more effective use of the reservoir pressure. Any such treatment would not increase the reservoir pressure, naturally, but it would allow a more effective use of the reservoir pressure to come through the wall and force the gas out.

The correction of the pressure for the few feet between the bottom of the well and the edge of the new void created by the acidization is a great difference. It can be measured. It varies. In the use of acid in wells in that field and also Hugoton the open flow of the wells has been increased materially, in some cases several hundred per cent. That means, as we have said before, that the pressure is the
32 motivating force and forces it up. If you have higher pressure you get more gas, the same thing in the well.

The acidization would not affect the shut-in pressure. I think it would affect the operating pressure—the flowing pressure, but I do not know to what extent in terms of

pounds. I know that the open flows of wells that have been treated have been materially increased. Those open flows could not have been increased unless there was a change in pressure between the sand source and the source of the limestone and the wellhead. If you didn't increase your pressure you wouldn't get any more gas than you had before. It is the differential in pressure that causes the flow, and that differential is increased. The wellhead pressure would not be changed, that is, the shut-in head pressure, but the flowing pressure would.

In explaining how you would have an increase in differential and also an increase in pressure at the wellhead, and still have the same pressure conditions in the reservoir, I will state that the pressure in the reservoir is widespread. The pressure in the reservoir is a certain amount that is pretty well uniform. At each well bore that pressure is lowered because of the draft of gas out of that particular area drained by that particular well. Now, the amount of gas that that well can produce under any given condition, either under open flow or under production against back pressure, such as pressure in a gathering line, with no treatment at all, but simply the well bore into the formation is a certain amount. The amount of gas that that well will deliver into your gathering line is a function of the effective differential of pressure between the bottom of the well and the wellhead. Now, if in any way that differential in pressure between the bottom of the well and the wellhead can be increased, that well will deliver more gas under the same conditions.

Now, the effect of acid treatment is to increase the size of the bore around that area that the well is producing from. It is a chemical proposition that hydrochloric acid is inserted into the well; it spreads out from the casing, comes in contact with a limestone formation and there is a certain chemical reaction whereby and whereunder this calcareous and limestone formation, a portion of it, is dissolved by the acid or changed into carbon dioxide and water and voids created in there, or channels created in there, where this gas can come in. So it is just the same as if you took one of these little tea strainers and you could deliver through that so much fluid. If you take a strainer three or four times that size you can get several times the amount of fluid through it. Now the differential increased. I mean, the differential is in pressure between the bottom of the well and the wellhead, due to the fact

that it is easier for this gas to get from the formation to the well bore.

It comes out of the wellhead at the same pressure it was coming out before and the differential is the increase in pressure at the bottom of the well. In getting gas from the well to the compressor station the acidization will maintain the pressure for a longer time for a given definite flow of gas.

33 With reference to how you are going to get the gas to flow from the wells to the Fritch station when the pressure of the wells has been reduced to the same level as the intake pressure at Fritch station, I believe I stated that if and when that time comes that the wellhead pressures of the wells you have now in operation on your leases in the Texas Panhandle field are reduced, after having done everything you can do—and, of course, we know that the amount of gas available in that field as well as any other field is limited and we do know that in fields the casinghead and the reservoir pressures all go down. We expect that. When that happens, then the pressure at which that gas from those particular wells you have now delivering into your gathering lines will be lower than it is now, naturally.

If you cannot get the volumes necessary to build up the load going out of the compressor station, there are several things to do to overcome the situation so that you can get enough gas into your compressor station to supply your pipeline with its requirements at, say, 200 million cubic feet of gas or more.

First of all, the question comes up as to whether or not you have drilled up your entire leases. If you have not, then one thing would be to drill additional wells. If you drill additional wells, those wells will then produce and will become additional sources of supply up to the limit of your reserves. Another method which has been used is to put boosters, pressure booster stations, in the field. In some places that has been done. Where the pressure of the well has been reduced in some cases down below atmosphere, the well has been put on a vacuum, and gas has been sucked out of the well. They don't get as much gas out that way as they do from a flowing well, but they get a good deal. Of course, that is more costly. You have to have your compressor stations and booster stations out in the field, and you do not have to have them when you have flowing wells.

The drilling of additional wells on the leases will not build up the pressure on the old wells, but it may further

delay the time when that pressure will be reduced down to a point when you cannot use them. In other words, any new wells drilled would supplement the supply and hold up the rate of withdrawals from the wells already drilled. Whether if those wells are drilled on Texoma's leases there would be a higher pressure in the new wells than in the old ones would depend on the portion of the field and on how far the new well would be from present production. If there is a well now drilled in Fritch and you drill another a half mile away on the same section, you probably wouldn't find the pressure a great deal different in the new well than that existing in the old well which had been in operation a long time. It might be a little higher. It would have to be a little higher or there wouldn't be a flow of gas to the well. That is true of any two adjacent locations if they are close enough together. The closer you get them together, the nearer the pressures are to being the same.

Exhibit 12, which has been introduced in evidence,
34 shows the pressure conditions in the field. The greater bulk of Texoma's properties appear to lie in the West field, as shown on Exhibit 13. Those large patches of yellow in Moore County appear to be in an area that is from 350 pounds of pressure up. The original pressure was 430 pounds. I would say a good deal of that yellow there is in a territory that is indicated to have a pressure of 400 pounds gauge and over. The main productive property of Texoma is scattered over the whole field. There is a large area in Carson County that has no wells on it, and in that area the pressures appear to be from 200 to 300 pounds. The pressure has gone down 40% at the present time. I note from Exhibit 12 in the regions to the east and southeast of Dumas there is quite an area where the pressure is still above 400 pounds. I don't know offhand why the pressures would be so much lower to the southeast and to the north and northeast and to the east of that particular area. Part of that is sour gas area; that is, that portion of the area north of the dotted line shown on Exhibit 12 is sour gas. However, a substantial portion is in the sweet gas area.

I have stated that as the pressure goes down, the potential open flow of the wells is going down to where it will be necessary to drill other wells in order to keep up the requirements of the pipeline. It will be necessary either to drill other wells or treat the present wells with acid, or

both; but it is the inevitable development because, after all, you have only a certain amount of gas in there.

I do not know how many more wells Texoma will have to drill in order to produce its requirements of gas down to 100 pounds pressure at the wellhead. I have made no study of that at all. In order to get the gas to the present gathering system, when you drill a new well you will have to tie that well in with the gathering system—you will have to build a pipeline and install a meter to measure the gas as it goes into the pipeline. When the pressure gets down in all of those wells to the point where they are substantially at the same level as the intake pressure at the Fritch station, you are going to have to put in booster stations in order to get the gas there in sufficient quantities to fill that pipeline, if you maintain your intake pressure what it is at Fritch. It is necessary to keep that discharge pressure into the Fritch station at substantially the present pressure in order to get a volume of gas into the station to load the pipeline under the conditions you have there. In other words, it appeared to me that those units were pretty well loaded up, and, of course, if you substantially reduce the intake pressure in that station you are going to cut down the volume of discharge. If you do maintain that volume, of course you will have to get the gas in there at that pressure.

You will have to build up the outside pressure in order to get the gas to flow in there at that pressure, which will require the building of additional compressor stations, or it will mean the installation of additional compressor units at Fritch so you can handle intake pressures lower than you are now handling them. It is a foregone conclusion that you have got to have the compression at one place or the other. You have got to have it in the field or you have to have it at Fritch.

35 As stated, I do not know how many additional wells you will have to drill and have made no estimate of that or given it any thought or consideration.

At the time I examined these properties in Texas, I talked with the operators about the properties and the operation of the system, and I have studied the answer of Texoma Natural Gas Company and Natural Gas Pipeline Company of America to the Commission's Orders Nos. 51 and 53. In the answers to Order 51 there purports to be a description of the operation and of the properties.

In my testimony I referred to delivery taps, but I didn't

mention any special distance between them. A delivery tap is a lateral tap from the main line, as indicated on the map accompanying the companies' answer to General Order No. 51. That is a place where gas is carried away from the main line off to some place for delivery. I did not mean to infer by my testimoney given at first or that later given in connection with Exhibit 14 that these lateral lines running away from these delivery taps to the main line belonged to Natural Gas Pipeline Company. I have noted on Exhibit 14 a delivery tap at Beaver, Oklahoma. Beaver is shown on the map accompanying the answers to Commission's Order No. 51 by Natural Gas Pipeline Company; but I would have to check to see just where I got the information that there was a tap at Beaver. I mean that the map submitted shows the town of Beaver. Exhibit C attached to the answer to Order No. 51 shows that the delivery point was near Beaver, Oklahoma. It says it is in Section 16, Township 16 South, Range 12 West, Barton County, near Beaver, Oklahoma. What I referred to there when I put this tap on that map was this particular sale and the fact that the answer to 51 said that the delivery point was near Beaver, Oklahoma, so I used that point. Wherever that delivery was is what I referred to.

I stated the acreage belonging to Texoma to be 153,795 acres. That was given to me by the gentleman I talked to down in Amarillo, either Mr. Peterson or Mr. Dickinson. I think they gave me that total. I do not know how many wells are located on that acreage or how many wells are drilling on it.

I have referred to a number of exhibits, numbered 3 to 6 inclusive, which are tabulations of figures. Those are figures given me by Mr. Johaningsmeir, taken from the books of the companies. They were prepared by him and he reported to me. Mr. Johaningsmeir is the gas engineer in the employ of the Federal Power Commission stationed in the Chicago office, and he is working on the investigation of the operations of Texoma Natural Company and Natural Gas Pipeline Company of America under my supervision.

As to whether in our investigation we have treated the companies as constituting one project or two separate projects (objection by Commission Counsel), we have not gone on any hypothesis or premise. We are simply trying to find out the facts. We have here a company under the name of Texoma Natural Gas Company. We have a com-

pany under the name of Natural Gas Pipeline Company of America. Both of those companies filed answers to the orders of the Commission, and in our investigation and in any phase of the investigation that I am making or conducting or that is being conducted under my supervi-
36 sion we are not going into it with an answer in mind. I don't know. We are going in to find out what are the true facts.

There is no special significance in the fact that we have made the exhibits as we did. There is no significance in the fact that in our Exhibits 5, 6, 8, 9, and 10 we show figures for the years 1934, 1935, 1936, 1937 and 1938. It is generally our custom to go over a five year period. Since this company has just had a seven year span of life, we might just as well have gone over the seven year span. The fact that they did not make any money the first two years did not have anything to do with it. In fact, I think in fairness to the companies involved here, and due to the fact that the whole period is about two years more, we might well consider the whole period.

I spoke of sectionalizing valves in connection with the pipeline, and stated that there were nine compressor stations on the main line and one station at Fritch. A sectionalizing valve is simply a valve on the main line by which certain sections of the line can be cut off, particularly in the event of breaks or outages. In other words, the line can be sectionalized by closing these valves, which are valves on the main line. In case of trouble at a given point, the valves on each side of that point can be shut and minimize the wastage of gas as a result of that development. I think I stated in my testimony that those sectionalizing valves are placed at ten mile intervals up and down the line.

I referred to the fact that there were cross tie connections and meter setups installed for emergency use at points where the line crosses the Panhandle Eastern line near Fowler, Kansas, and also where it crosses the Cities Service line near Lincoln, Kansas, and also where it crosses the Northern Natural line near Pacific Junction in Iowa. By emergency use I mean that it is common practice among pipeline companies to have inter-connections with other lines that may be used in case of emergency, the idea being that those connections serve as a standby for both companies in case of emergency. In other words, if the crossing down on Canadian River were to go out, or at some other point between there and the cross connections here, the

company would be able to supply its emergency requirements through courtesy from another pipeline, and they in turn would be able to obtain the same courtesy in case of a similar situation, assuming, of course, that at the time the event occurred, the furnishing company had available gas to furnish, which I believe they ordinarily would.

I used a figure of 153,795.14 as the total acreage of Texoma in this field. I believe Mr. Morgan made mention of the figure of 154,155.14 acres. I checked that up during the noon hour, and according to the records of the company there was an amount of 360 acres that is included in the figure mentioned on which the company has oil rights only and not gas rights, so the figure for the gas acreage then, the difference is the figure I used, or 153,795.14.

I know there is in Texas a statutory limitation with
37 respect to allowing 25% of the potential of the well as a maximum which may be produced. Whether or not that applies to both sweet gas and sour gas I do not know.

I do not know in inches or anything of that sort how far out into the formation acid operates or exercises its chemical effect of eating out the natural formation. It is probably not very far. I presume just a few feet, because the practice is to introduce the acid and then remove it shortly thereafter.

My information with respect to the location of the formations is that the basement rock first consists of the granite, solid granite, buried Amarillo Mountains, on certain slopes and on certain portions of those mountains there occurs this granite wash. Then after that occur the limestone deposits. Then above that the so-called red beds, gypsum, salt, and so on up.

I understand that the dolomite formation in the Panhandle varies in thickness. It may reach in certain places a thickness in excess of 100 feet and in other places very much less. There is some variation in porosity, and there is quite a difference in the porosity of granite wash and the dolomite.

I presume that the point of setting the casing in a Panhandle well drilled into the granite wash formation varies. The setting of the casing would vary, possibly, somewhere near the middle of the thickness of the wash. In some cases it would extend half way through the granite wash. It may vary. Providing a seat for the casing depends on the hole. I think they use a shoe in some cases. I don't think I can answer what the difference is in the

method of providing a seat for casing in the dolomite and in the granite wash.

As to difference in depth or location of the casing seat in the brown dolomite and that in the granite wash with reference to the producing part of the formation, in the dolomite, or what is termed the big lime, I believe there is less tendency to cave than there is in the granite wash, so in most cases I believe the casing is set down toward the bottom of the producing horizon in the dolomite. As to the granite wash there is much less production from granite wash in speaking of gas than there is from the dolomite. I am not so familiar with that granite wash operation.

I think the bottom casing is further up in the dolomite than in the granite wash because there is less tendency to cave. As already stated, I have had nothing to do with the drilling of any wells or the setting of any casings in the Panhandle. My information is general geological information which I have picked up in my contacts down in Texas and in looking over well records and talking to people who have drilled wells there.

I talked with representatives of the Texas Railroad Commission at Austin, Texas. I did not talk to any other representatives of that Commission except in Austin.

38 Austin is located in the southern part of Texas as compared to the Panhandle, which is located in the northwestern section in the Panhandle area, I would say something like 600 miles away. My understanding is that the Railroad Commission makes pressure tests over the field, at least portions of the field, every six months. The members of the Commission with whom I conversed were Mr. Langford and Mr. Blair. I do not know who the predecessor of Mr. Langford was in the Texas Railroad Commission. I have heard of a man by the name of Cottingham. I can't say how long he was connected with the Commission; but I have seen a great many reports of the Commission pertaining to gas production and gas regulation in the State signed by him as chief engineer, and have consulted those reports in getting the information I have given in my testimony here.

(Map entitled "Ideal Cross Section—Portion of Texas Panhandle Field," marked Exhibit 16 for identification.)

Exhibit 16, with the caption "Ideal Cross Section—Portion of Texas Panhandle Field," is now submitted to me. I am familiar with what it delineates and with the legends which explain the coloring on the cross section.

I spoke of a buried granite mountain range in the Panhandle. That is an old mountain range that at one time in geologic ages was apparently above the surface and exposed to the air at the top. It was apparently flanked at that time by the Anadarko Basin to the north and the West Texas Permian Basin on the south. Evidently at some period it was submerged, and at some time it was flanked by water. In other words, it had its ups and downs in its history.

Back through the geological ages, one time it has been up above the water so that the weather was getting in its work, and another time it was submerged below the water so these deposits of other formations were laid alongside and over it.

In the lower portion of Exhibit 16 are two upright projections and across each one is written the word "granite." That probably fairly portrays, in my judgment, a cross section of the granite mountain in some portion of the Texas Panhandle. On the flank of the mountain I see the words "granite wash" and the coloring is just a little different from that of the granite. That deposit is probably eroded granite, disintegrated granite, probably from its peak, weathered off on the slope under the influence of wind and weather and finally water. At a time when this mountain range was submerged these various layers or strata of one formation and another were laid above that two or three thousand feet to the surface.

The irregular line running from the word "south" to the word "north" on the cross section is possibly fairly representative of a part of the surface of that gas field. There are arroyos and gullies. You can tell within limits from experience in other wells drilled in the vicinity how far it is to one of the formations; but the wells are not all of the same depth from the surface down to the producing formations. They vary.

The dolomite is that portion of the formation from the top of the granite wash up here to a line above on which is written in two or three places the words "red bed."
39 That is the deposit of dolomite and anhydrite to which I testified. It varies in thickness from one hundred to several hundred feet from the top of the granite wash up to the beginning of the red bed. Through that dolomite formation there are strata of varying porosity.

The green colored part of the formation is meant to represent oil deposits. Down below that is a heavy line

marked "sea level." I don't think I stated that the formations laid on the flank of the granite mountains, whether granite wash or dolomite, dip off into water. I believe I stated that the depth of these wells or the average depth of the producing formation there corresponded roughly in many places in this field to sea level. Below sea level in the porous part of the formation that dips down into the region below sea level is probably found sea water or salt water. This may or may not mean that this water is directly connected with the ocean at this time. I believe I stated in my testimony that so far as I know it is a mere coincidental circumstance.

If you are up above sea level in a porous formation, either in the granite wash or in the dolomite, which is sufficiently porous, you are getting close to where oil may be found anywhere on those flanks of that mountain in that field, particularly on the north strip as shown in Exhibit 12 in that oil belt on the northeastern section of the field.

(Map entitled "Rock Pressure Map, Texas Panhandle, 1938," marked Exhibit 17 for identification.)

Exhibit 17, captioned "Rock Pressure Map, Texas Panhandle, 1938," is now exhibited to me. I can't say I have seen that exact map. I saw a map in Amarillo that Mr. Peterson had showing the various pressures in the field on either 20 or 50 pound contour. That may be the same map. I don't know. The map I saw was not colored. This looks substantially like the same map I saw in the hands of Mr. Peterson. Upon comparing this map with Exhibit 12 I find some difference in the pressure areas, that is, the areas for the different pressure bands. As I say, I am not just familiar with the map you have just marked for identification. I know that on the Railroad Commission map those pressure areas are shown on the basis of 50-pound contours.

I have said that oil was found mostly along the northeast flank of the field. I don't know what part of the field the ideal cross section traverses. Counsel informs me that the line is run in an irregular direction to strike the actual wells so that they can portray the actual well logs. An irregular line runs in a general direction from north to south to the points B and A. These are located just to the east of the line which marks the east boundary of Block 2 and Block 5 in the central part of Carson County. Assuming this statement to be correct, the green colored formation on the cross section would probably be found

in the northeast flank. I don't think it is true that as you leave the northeast flank you go up the structure until you hit the top of that mountain, that buried mountain, and it slopes off in the other direction. You don't find oil all along that flank; but it is largely concentrated in that flank. That is where most of the oil wells are in that area.

40 The black spots shown on Exhibit 17 indicate oil wells. There is a designation showing a difference between oil wells and gas wells. The gas wells are indicated by stars.

If you drill a well over in that area there that is portrayed in green on the cross section and go on through the red bed, you come to the so-called hard rock cap on top of the big lime which is called the anhydrite formation. You pass on through that and through the lime dolomite until you get down ultimately to the granite wash probably, if you happen to drill a well in the location in which granite wash is under lime. The granite wash is liable to be at various places either where there is no gas above the oil or next to the side of the mountain, but it is generally close to the peaks. It is washed off the side of the mountain and that is why they call it granite wash. It is alongside the mountain and extends out for a comparatively short distance from the core of the mountain and generally hugs the flanks.

If you drill a well over at the location of the first black line extending from the surface, the small picture of a derrick, down to the area colored green in the formation, which has been described as porous layers in the dolomite, you encounter an oil bearing formation, according to that chart. You might and might not encounter gas in that well. You might pass through some gas on the way down. When you got down to the oil, if you did succeed in securing and producing an oil well, you would produce gas probably with the oil. That is what I referred to the other day as casinghead gas. The way this first from the right is located, if the well were cased off above the oil you would get oil and casinghead gas.

The portion of those layers of dolomite which are painted red typify what might be termed lenses or strata containing dry gas in a free condition. If you drill on down through that to approximately 90 or 100 feet above sea level, you have a chance of encountering another porous layer or lens which will bear oil, depending on where it is located. It is often the case in the Panhandle that

you get gas from the upper formations or upper layers of the formation and go on down and get oil in the same hole down in a layer of the same formation but at a lower level—you might term it a lower lens or lower layer of the formation. If you drill on down to sea level you might encounter water.

If the water were not successfully plugged up at the bottom of the well and you pull the well very hard, that is, produce something approximating the maximum possible production of that well, you very possibly would cone up that water in the hole up through the bore. There is this to be taken into consideration, that the oil and gas interface with the water. By that I mean the contact is approximately at sea level by coincidence, if you please, so there is no decided tendency of water drive into the bore.

There is no drive from any distance into the oil and gas.

41 If, when you drill into the water, the lower end of the well is left open and exposed to water, the reservoir pressure would cause the water to rise in the hole. The height to which it would rise depends on the condition of the hole and the pressure involved there—how much you are pulling on the well. I don't believe one could state that the water would rise a certain definite amount. It may be a commonly accepted fact in the field that the water table rises approximately 1000 feet in wells as the pressure goes down. As I stated in my direct testimony, the virgin pressure of 430 pounds at the well head is a subnormal pressure. In other words, it is less than half the pressure one would expect from the static head of water of 2600 feet. I think that is brought about partly due to the fact that the water level occurs at about sea level, and other factors. 430 pounds is just about the weight of a 1000 foot column of water. There would be a balance in there.

As the gas is extracted or produced from the formations above the water, the pressures naturally go down. I don't think the danger of water coming up necessarily increases in the same ratio as the pressures go down, for the reason that as the pressures in these formations go down your motivating force raising the water up also goes down. When you come to the time when you deplete it, the pressure in those formations there is enough to raise that water above sea level. The pressure in those formations is not still 430 pounds. No doubt there are areas in the whole field that have pretty close to virgin pressure.

There may be spots where the pressures have gone down as low as 50 or 60 pounds. I do not know of any such areas, but I would not be surprised. The pressure probably does not go down in the oil as quickly as it does in the gas. I don't think it is true that you have your reservoir pressure in the main body of water, after that pressure has been released, and gas formation above it. I think the pressure in that reservoir is due very probably to the entrapped gas that is there and held there by the cap rock and the top of the formation and by the basement rock. Possibly the water is itself resting on the basement rock. I think the granite is the bottom of the whole business. I don't think there is pressure in the granite. I believe that is the gas pressure itself, and whatever it was that exerted the original gas pressure there caused a pressure. That the pressure, after the arching of these formations, probably migrated up from source formation and that it was as it was when it first migrated there. I think the water followed it in under the Wichita Mountains, as I said in my direct testimony.

I don't know whether it is a fact that the water first came in there and is exerting a pressure equal to the weight of the column of water at the source. That is one theory; but I don't think it has been substantiated. I believe the very fact that the water level in that field is approximately at sea level would indicate the non-existence of a water drive or static water head. It may be as you point out that there is a static load which is exerted back from the Wichita Mountains, over a long period. That is a theory. I don't think it is substantiated. Another theory as I understand it, is that at the time these formations were arched over those mountains, either this oil and gas and possibly some of this water were in place, and it is not impossible in my opinion that the virgin pressure, subnormal as it is, of 430 pounds on the casinghead, is a pressure of oil, gas and water that was created there at the inception.

I believe that the gas and oil were probably formed
42 in one of those basins, probably in the Anadarko Basin to the northwest, and that it migrated after the arching of this Amarillo arch up into the highest point it could go. The highest point it could go was immediately underneath the anhydrites. It was cut off by the anhydrites and could not go any higher. Natural migration from the

source beds made it come in there. It probably had some pressure at the source bed and moved because of the tendency for oil and gas to migrate.

I know this field is bounded by the lines shown on the map. There is probably a physical connection between the reservoir as now located and the source bed right through the middle area. North of the middle area along this dark heavy line the formation dips off into the Anadarko Basin and there is apparently water between it and its source bed. The reservoir is found at the beginning to have had 430 pounds pressure per square inch measured on the basis of 16.4. As to what caused it to move in there and accumulate any such pressure, if it wasn't for the water, I believe the natural tendency of the oil and gas, the relation between the oil and gas themselves is for the gas to seek higher levels and the oil generally is found in lower levels. Underneath that, then, further under that is water. I believe it is an actual separation. The thing that caused the gas to come in and seek its altitudinal higher level was simply the presence of a porous medium connecting the two and the tendency on the part of the gas to seek the higher level. When those substances are in the same container they separate—the water at the bottom, the oil above the water, and the gas above that. Thus in this container we find the gas in the upper porous part of the container.

Coming back to Exhibit 16 and considering the whole reservoir reflected in Exhibit 17 as a container, it is my idea that since the porous portion of the formation overlying the granite ridge painted in red is higher than the others, that is the natural place for the gas to be found in association with the oil and the water in the same container. Between that point and the water the oil would be found.

You have requested me to explain how it is that the gas comes off from some distance up to that formation which dips down into water and gets into this container and finds its place, coming from where the gas was formed in the Anadarko Basin, and whether it would find its way through the water in getting into the position in which we find it as portrayed on Exhibit 16. My answer is that it is probably impossible to say just exactly what the relationship was between the oil, gas and water at the time this migration took place. The very tendency, at least the very porous condition of this reservoir material, capillary action and other physical action, probably had its place in assisting

the migration of these fluids. Just what relation the water was at the time this migration took place is impossible to tell. One thing, however, is sure, if you have a source material and a source area you also have a natural catchment basin formed by the arching of these sedimentary deposits over the granite mountains. Having those conditions and knowing the natural tendency of oil, gas and water to separate, with the gas on top and the water on the bottom, the porosity of the medium in between, to my mind, answers the question.

If I remember correctly, I made the statement that probably these buried Amarillo Mountains under the Texas Panhandle field were an extension of the present Wichita Mountains in Oklahoma. I wouldn't say that it is a
43 substantiated fact that those same Wichita Mountains formed the source of the water which underlies the great gas reservoir in the Texas Panhandle. I am not so sure of that. It is a theory that some people hold. I don't know that I can quote anyone who holds to a contrary theory; but I heard discussions—I have seen some papers and I have talked to people about the thing. I have made no independent researches on it myself. I have made no research except to refer to some literature that I found pertaining to the Panhandle written by other people who have made researches, and have talked to people as well. I have made no tests to determine where the water existing in the Panhandle field comes from. I do not know that water comes up past the well bores and gets into the gas bearing part of the formation and that there are wells down there producing water. I know a number of wells have been abandoned; but whether on account of water itself I could not say. I understand they were abandoned at pressures in excess of 100 or 150 pounds; but do not know how many there were.

There is always the possibility of water getting into a gas well in the Panhandle unless it is properly cemented off or sealed up. You encounter salt water bearing formation up above the hard cap rock known as anhydrite, and if the water is not properly cased off in this formation when it is encountered, it will go down the well bore to the gas bearing formation, and if it gets in there it will flood the formation and drown it out in many instances. The well will go dead even though it still has 100 to 150 pounds pressure; but I think you should also take into con-

sideration that the intrusion of water into a well is one of the things that is guarded against, and every attempt is made to case off any water source that is encountered in the drilling of a well. So that won't happen. I do not know in how many wells they have failed to succeed in doing this. I think there are something like 300 wells making water.

I am familiar with the history of oil production in the Panhandle to some extent. It is a matter of common knowledge among the fraternity that in the early history of most of the fields the oil operators did not put any value on the gas. They were looking for oil and weren't very careful when they drilled the wells to case off the water so as to protect the gas.

You point to a rather heavy band of red at the location between the fifth and seventh of the wells portrayed on Exhibit 16. I do not know why that band is wider than the band traversing Nos. 3, 4, 5 and 6. I assume from your statement that the band has the thickness indicated and that the band near the green area which traverses the wells numbered 3, 4 and 5 is much more narrow and that those correctly reflect the thickness of the two producing formations producing gas. If the thickness of the red band that you have just called attention to indicates the thickness of the formation, which is what is generally known as pay, then I would assume that where the band is thicker, the pay is thicker, assuming the porosity to be the same.

Again discussing Exhibit 16, you point out some
44 short red bands at different portions of the formation.

I believe those portray small lenses—gas formation—and assume that the formation which yields gas is not uniform through the great territory covered by that reservoir. In other words, as I stated in my testimony, very probably the thickness of pay varies. The number of layers of strata of porous substance found within the limits of the three or four hundred feet of dolomite underlying the anhydrite probably varies, maybe 5 or 6 in any one spot, and it is not infrequent in the Panhandle to encounter a lens in a given well, such as No. 7, which is not encountered in No. 6 or No. 8.

In the light of the fact that in many of those wells local lenses are encountered, it would be my judgment that there are other lenses in between wells of the same character—small lenses not extending any great distance from the place where they are located. Those small lenses are in

some way connected with the porous lenses, probably through the general medium of the structure. I would say if that exhibit, if its portraying of such lenses is representative of the conditions there, that there must be some reason that gas is held in those relatively small portions as lenses. There is bound to be some way for the gas to come in the upper formation, seeking the highest points to get into those little spots. I believe that almost over the whole field there must be some more or less general physical connection due to the fact that the original or virgin pressure was largely the same over the entire field.

If you find gas in one of those little places, or if you find it in the big band like the one between well No. 5 and well No. 7, or if you find it in a confined area like the last well over to the left-hand side, the pressure was all originally the same—approximately 430 pounds at the wellhead. That, with the exception of one area where it was higher, is true whether it was sweet gas or sour gas. No matter where it was found inside that reservoir, the pressure was substantially the same.

This indicates to me that there is a physical connection between the different layers or strata which produce gas. That connection may be a connection through which gas might be slow to percolate, but nevertheless it indicates to me there is a physical connection between the source of supply.

It is probably true that in the case of those small lenses the chances are it would take some time for gas to get from one of them down here to one of the other formations. First of all, you would have to have a pressure differential to have a motivating force to make it go down; otherwise it would not move. If there are lenses which still retain their pressure and the other measures are depleted and the reservoir pressure is reduced, there will be a greater chance for the gas in those lenses to move over to the lower pressure area, depending on the character of the formation between those lenses and the places of lower pressure.

Questions by the Examiner.

As Exhibit 16 does represent a cross-section through the Texas Panhandle field approximately at the point indicated, it very probably does represent a fair cross section of the structures in that field along that particular line.

As I say, that is of the formations—the picture portraying the conditions as they exist there—which I understood him to say was made up from logs of wells as indicated on there. I do not know whether Texoma has leases directly on that line. It could be determined by consulting Exhibit 13. It depends on where in Carson County this selected line exists. If it happened to be in the eastern portion of Carson County, there is, according to Exhibit 13, a substantial acreage under lease to that company in that area. The relationship between gas and oil in the western end of the Panhandle may not be the same as that shown along this cross section. As I understand it, all Exhibit 16 purports to be is a typical cross section on a given line.

Further Cross-Examination by Mr. Morgan.

If you were to go northwest and use a cross section of the field along the east line of Moore and Potter Counties from north to south, you would not get just exactly the same contour in the granite mountain range that you have in the middle crossing. It would be a coincidence if you did. These mountains are like all other mountains, irregular and situated with reference to each other in all kinds of ways. Throughout that reservoir you might find this granite peak much higher somewhere else than you would find it at that particular line. You might find it to be one cone instead of two. You might find it isn't on the same line. There is no uniformity about it; but the granite mountain would form the basement wherever it happened to be, because the sedimentary rocks that have been deposited and in which the oil and gas are found have been folded upward by reason of the presence of the range of granite mountains. If you take a row of wells across the field in any position, you will have the same comparable situation, though the number of formations bearing oil and gas may not be the same and may not be the same distance apart; but if they are there they will probably have the same relation to the oil bearing and to the water bearing part of the formation and to the granite basic foundation. Generally at the bottom will be the basement rock of the granite peaks and then probably some granite wash, depending on where you draw the line. On top of that is dolomite and anhydrite, and on top of that the red bed.

As shown on Exhibit 16, between wells Nos. 1, 2, 3, 4 and 5 from the left side there are probably many interconnections between the various gas lenses and the various strata. The same condition obtains, generally speaking, whether the well is located in the sweet gas area or in the sour gas area.

I pointed out the sour gas line on Exhibit 12. It is a broken line starting southwest of Pampa and running in a generally northwesterly direction up through the field and coming out of the producing formation near the west line of Potter County. That is supposed to be the division between the area that produces sweet gas and the area that produces sour gas. By sour gas I mean gas that contains an objectionable amount of hydrogen sulphide or sulphur. Sweet gas is made up of the other hydro-carbons and does not contain objectionable amounts of sulphur or hydrogen sulphide. The division between sweet gas and sour
46 gas is not a fixed thing chemically. No certain standards have been adopted as to what are objectionable amounts. I believe in the contract between Texoma Natural Gas Company and Natural Gas Pipeline Company of America it is clearly set forth as to the limits. It is often defined by contracts, and down in Texas has been defined by statute for certain reasons. Sour gas can be used for the manufacture of carbon black and sweet gas can not. I am familiar with that distinction down there. For the purpose of applying that distinction, the legislature of Texas has defined sour gas as containing 1½ grains of sulphur per hundred cubic feet; and the broken line shown on the map is the line that now divides the areas which produce gas containing a grain and a half or more per hundred cubic feet from those which contain less than that.

I have examined earlier maps showing the location of that line and found that it had been moved and its location has been conceived of as being differently situated at different times throughout the history of the field. Back in the earlier days they probably did not know as much about where the line was located as they do now. Additional drilling has probably more definitely located it, the same as anything else—additional information and later information. Then there is also the fact of the withdrawal of gas of different types—I mean by that sweet and sour gas. Back of the time when they had as many wells in the vicinity of that line as are now located there, they were

less certain of where the line was situated, and the line has actually changed its physical location in the formation during the past several years from where its existence was known some eight years ago. It has moved to the northeast. The phenomenon of the moving of the line of demarcation is very probably due to the large amounts of sour gas and casinghead gas that have been produced in the field from the northeast flank. The tendency would be to reduce the pressures in that portion of the field and pull the sour gas line to the northeast—pulling sweet in to take the place of the sour which has been produced. There would be a tendency of the gas to move from the higher pressure portion of the field to the lower pressure portion, as shown on Exhibits 12 and 17. The lower pressure area is along the oil part. That is not just a tendency; it is an actual fact. It has actually happened.

There is nothing which separates the sweet from the sour gas in that formation. Both kinds of gas will lie in the same layer of porous strata up on the slope of the mountain. I can't give you an explanation of why it is that there is sour gas on one side of the line and sweet gas on the other with nothing to separate them; but that appears to be the situation.

Looking at Exhibit 12, I see a great many wells described as oil wells and indicated by black dots, most of which are along the northeast flank of the reservoir. Some of those wells are in a band having a gray color or the color next to it, and some of those wells are in an area which is not colored at all though within the black line that marks the boundary of the picture portrayed here. The uncolored portion of the oil producing area within the boundary of the field indicates an oil producing area with probably little or no gas production. The gas producing area is given some color. Above and to the northeast of that
47 producing area is quite a wide area that produces oil but no gas to speak of. It may produce some casinghead gas; but the Texas Railroad Commission, who made this map, indicate that as the oil-gas line, or some such name. If we apply that line to Exhibit 16, it is probably the line marking the extremity of the bands colored red, beyond which there is no free gas but only casinghead gas. I have defined that term in my direct testimony.

It is true that while there are oil wells scattered over the entire area which is not colored on Exhibits 12 and 17,

there are also many oil wells in the colored portion which bear gas. Those are the wells that are located in situations comparable to wells Nos. 2, 3, 4 and 5 of Exhibit 16, where they penetrate the gas as they go on down and then find the oil in the lower strata—either that or where they penetrate oil producing measures and produce oil and casinghead gas from those measures.

For example take well No. 1. That apparently goes down into the green and does not hit the red. That well would probably produce oil and casinghead gas. Take No. 2—apparently that well goes through the red band and goes down into the green, and so do Nos. 3, 4 and 5. I see nothing on that chart to indicate whether or not those wells are cased off through those gas measures. Assuming that they are cased off through the gas, they produce oil and casinghead gas from the oil measures colored green. It is true that in the same area which has free gas, such as that contained in the red formation pictured in Exhibit 16, we also have oil wells producing from the formations below the red—that is, producing from the green or oil measures.

By casinghead gas I mean gas that is produced from an oil well. A substantial portion of it is dissolved in the oil in the reservoir. As to whether there is a difference between dissolved gas and absorbed gas, I do not know just what you mean by absorbed gas. You might speak of a substance such as charcoal which absorbs and absorbs great quantities of gas. When I speak of dissolved gas in petroleum I mean gas made liquid under pressure. It has taken on a different nature while it is in association with the oil and is in the liquid phase. When the pressure is reduced it goes back to the gaseous stage, and that is what I was talking about when speaking of casinghead gas. I also included any gas that was produced from oil wells in conjunction with oil, even though it came out of the upper formation. I was not classifying it as to its source but as to the place where it was produced, if it was produced from an oil well; even if it came out of the upper red bands I still called it casinghead gas, but with the understanding that very probably most of the casinghead gas produced was produced from the oil and the other measures were very probably cased off.

It is my thought that most of the gas designated as casinghead gas may have been dissolved within the oil itself. A substantial portion of it may be there when the gas is

formed, but it is in those measures which are oil producing as distinguished from dry gas producing measures. I
48 do not want to limit myself to say that all of the casinghead gas produced is gas which has been dissolved in oil, but that a substantial portion of the casinghead gas that is produced with oil has been dissolved with it; but there may be gas in those green measures. It did not go up where the red is for the same reason the little lens I pointed out a while ago had not gone over to the red band.

I think there is some free gas down there in those green measures, because I don't think those green measures are free from catchment basins. I think that both oil and gas are found down in those areas that are below what is commonly known as the line marking the division between the gas and the oil. I didn't get that information from any geologist. The people who told me those other facts about the Panhandle didn't tell me that. I know that generally has been the case in numbers of fields.

Over in the southwest portion of Exhibit 12 are some irregular oval lines. They look like contour lines to me. Those small almost circular areas inside each other apparently represent depth contours as distinguished from the contours bounding the colored portions of the map, which are pressure contours. Those particular contours appear to be a depression. It looks like the part in the middle is lower than the circular portion around it, unless the contours are numbered from a datum plane, which may be sea level. If the latter is the case, the third or larger circle indicates zero, the next one is 200, and the next is 400. If those represent altitudes above some datum plane, then they would represent a dome.

I heard about the helium dome while I was at Amarillo. I can't tell you exactly where it is located, but it is somewhere towards the southwest of the field. I was not at the helium plant northwest of Amarillo. I heard about it, but I was never there. That seems to be located southwest of the western portion of the field. I noticed the portion of the colored map portraying the reservoir seems to run almost in a straight line along that southwest side. I think there is a fault line there. A fault line is a slippage of the earth's crust along a clevage plane either horizontally or vertically.

(Document entitled "Southwest-Northeast Section from Southwest Potter County to Northwest Hutchinson County, Texas," marked Exhibit 18 for identification.)

Exhibit 18 is now exhibited to me. That exhibit is labeled at the bottom "Southwest-Northeast Section from Southwest Potter County to Northwest Hutchinson County, Texas." I mean by a fault the line on this map shown toward the left of the center of the exhibit, and extending from the top of the exhibit down through the vertical line to the bottom. That line is marked "Potter County Fault."

I mean by a fault line a cleavage plane or slippage plane along which the measures on one side or the other have either slipped vertically or horizontally or in any combination of the two. Now, from looking at this map it would appear that there has been a slippage along its cleavage plane or this fault line in which either the portion to the right has been elevated or the portion to the left has been dropped, because apparently to the left here is a part
49 of the formation which is designated as dolomite series. The dolomite series on the right hand side appears to be somewhat higher than the one on the left.

Then next is a line called the Red Cave, which intersects the fault line at this point, which is at a lower point than the Red Cave on the righthand side.

The next is the salt series, which is green, and generally on down to the yellow, and which is designated on the righthand side by the same color and same name, which is higher on the structure than the righthand side of the fault line.

No one can tell, of course, whether the main reservoir was lifted up by some force back in early geologic ages or whether the part to the south which is faulted off of it was dropped down. There is no way of knowing that; but something happened so the thing was broken in two along that fault line.

The geological formations, when you encounter them, are substantially the same in the helium fault as in the main field but at different levels. That is the substantial difference. However, gas over here contains a substantially larger quantity of helium than it does in the main reservoir. I don't know why the sulphur gas and the sweet gas stayed on opposite sides of that line there. I haven't heard any explanation of it. I would like to hear one.

In this particular instance the existence of the fault line and the elevation or submergence of those measures on either side have their effect in producing different conditions. The pressures are different. The pressure in the helium dome is around 744 pounds. One explanation of

that may be the circumstance that you do not encounter the producing formation until you go down 700 feet deeper than you found the same formation on the other side of the fault line.

There is a little difference chemically in the gas in Moore County from that in Wheeler County. The gas in Moore County is nearly the true dry gas, having a larger percentage of methane. The gas down in Wheeler County has relatively lesser portions of methane and more ethane. So you frequently find differences in chemical constituents of the gaseous mixtures, the hydro-carbons, in any part of a large field.

I know what the total withdrawals from the field are estimated to be, including both dry gas and casinghead gas. I do not know where you could obtain the accurate figure on the total casinghead gas production from the time the field came in; but it has been estimated on various bases. The Railroad Commission of Texas indicated that over the Panhandle proper the gas-oil ratio is about 6 MCF of gas per barrel. By the Panhandle proper I mean the whole field—the whole part that produces oil. You have no gas ratio in the part that produces no oil. The over-all producing parts of the field are called the Panhandle proper; but they are sometimes designated the East field and the West
50 field. That is probably a classification for proration purposes for both oil and gas.

You inquire if that part of the oil producing formation lying east of the east line of Moore County down through Hutchinson northeast to Carson and central Gray and Wheeler Counties, except for a little area down here right at the southeast end of the field, is not the Panhandle proper. I state that that corresponds with my definition of it. That is the oil producing portion of the field. They also produce oil up in the northeastern portion of Moore County to some extent; but that is a separate designation. That would not be included in what might be termed the Panhandle proper, and the area known as the Osborne pool is not included in the Panhandle proper. There are three designations—those three designations; but all are in the same field. They are included in what is termed the total field. They are portions of what is commonly termed the common reservoir, and they are probably all connected directly with the gas producing formations extending out along the flanks of this mountain buried underneath.

From the investigations I have made and from an ex-

amination of maps as to where the gas which came from oil wells during the past ten or twelve years was largely produced, I will say it was largely produced from the high portion of the field called the Panhandle proper. Some was produced from the Osborne area and some from Moore County; but the great majority was produced from the Panhandle proper. The majority of the gas has been produced from that portion of the Panhandle proper that we have been talking about, including the uncolored portion of the map within the exterior boundary and the colored portion of the map.

Separating the great reservoir into two classifications, the oil area and the dry gas area, I will state that there is bound to be some overlapping between the two the oil measures being very probably under the gas. A great deal of the oil is underneath formations which bear dry gas. I do not remember the figures as to the extent of the overlapping. I think the Texas Commission tell about that in their report. I quote the following from their 1938 report:

"The field is approximately 124 miles in length and has an average width of 20 miles. It is composed of 1,076,423 acres which produce sweet gas, 398,901 acres which produce sour gas, and a proven or semi-proven oil producing area of approximately 250,000 acres. Approximately 40% of the oil producing acreage is included in the gas area due to the stratigraphy of the producing horizons. Oil production is confined to a series of pools extending along the north flank of the field for a distance of about 90 miles."

40% of 250,000 is about 100,000, so there are about 100,000 acres of oil bearing land out in the colored portion of the map. You refer to the original resting place in the producing formation of the gas which has been produced,

and inquire whether I think it came from the areas
51 where these oil wells are located, or whether I think it

has been drained in there largely from the gas bearing formations down the structure. I think both things have happened. I think there is a substantial amount of gas that was produced right from the oil measures.

You inquire what part of the six trillion I mentioned the other day was in the oil. In my opinion the total casing-head gas—that six trillion cubic feet on the basis of 6 MCF per barrel, is intended to indicate the total amount of gas that was produced from those oil wells, or I mean could be produced with one billion barrels of oil. Very probably

that gas came from two sources, one from the oil itself and the gas entrained with the oil or dissolved in the oil, and possibly some of it came from the gas measures adjacent thereto.

I know that petroleum at 400 or 500 pounds pressure will dissolve a lot of gas. I don't know how much; but the amount of gas that would be produced—at least I figure this—that the amount of gas that could be produced by producing from that field one billion barrels of oil would be equivalent to six trillion cubic feet of casinghead gas.

You present for my examination "Annual Report on the Panhandle Oil and Gas Field, August, 1938; Oil and Gas Division, Engineering Department, V. E. Cottingham, Director of Production." I have examined this document and find it is just like the one I have. The gas-oil ratio of 6 MCF or 6.1 MCF is included in a number of places in that report. It occurs on page 34 of that report and in the summary, which is page VI, at the bottom of the page. According to page 34 of that report, 6.1 MCF per barrel was the average gas-oil ratio for the month of April, 1938. The highest gas-oil ratio for the same month in the Panhandle field proper, according to the report, was 1350 MCF and the lowest none at all. That means that the gas-oil ratio varied from nothing to 1350 MCF. The fact that some wells have no gas-oil ratio is because those wells that produce no gas at all probably tap measures that contain no gas, in solution or otherwise. There is nothing in the report that says whether or not the 1350 MCF of gas came out of the dry gas formations, and there is nothing which says it does not.

On page 35 of the report the average gas-oil ratio for the month of April is given as 29.9 MCF per barrel. The highest gas-oil ratio in Moore County for that month is shown as being 4782 MCF and the lowest is shown as no gas at all, so even up there where those high gas-oil ratios prevail other wells contain none at all.

On page 36 of the report for the same month of April, 1938, the average gas-oil ratio per well for the Osborne field was 3400 cubic feet. The highest was 15 MCF and the lowest none at all.

In the same month we find the entire field showing variations in the gas-oil ratio from 3.4 in the Osborne field to 29.9 in Moore County. Amplifying that answer, I point out that the average per well of 6.1 MCF per barrel is

taken from an average number of wells reported of
52 3,411 in the Panhandle proper. On page 35 the average per well of 29.9 MCF was taken from an average of 20 wells in the Moore County area as against 3,411 in the Panhandle proper. In the Osborne area the average of 3.4 MCF per well was taken from an average of total wells reported, of 18, as against 3,411.

Of the 3,411 wells in the Panhandle proper, two-thirds had gas-oil ratios less than 2 MCF, and those two-thirds produced 44,131 barrels out of a total of 67,000 barrels of oil; but they produced only 37,369 MCF of gas out of a total of 413,339 MCF.

These figures which I have been quoting are taken from my copy of the annual report of the Texas Railroad Commission on the Panhandle field, dated July, 1938. It is a published report.

There is now submitted to me a copy of the 1937 report of the Commission. On page 28 of that report the following statement, headed "Gas-Oil Ratio," is made:

"During the past year one field-wide gas-oil ratio survey was ordered, this being during the month of October, 1936. Each operator was requested to make a ratio determination on each individual well while the well was producing its daily oil allowable. The report included the total depth of the well, daily oil production, daily gas production, and the amount of salt water each well was making, if any. These reports were all tabulated into ratio brackets showing the amount of oil and gas produced within each bracket. The average ratio was found to be 6.6 MCF per barrel. Ratio summaries on the Panhandle field proper, the Moore County area, and the Osborne area follows."

This report shows that the average per well in the field was not the same in October, 1936, as it was in April, 1938, but there was about 500 cubic feet per barrel difference. In other words, the 1938 average ratio as 6.1 MCF per barrel and in 1936 it was 6.6. In October, 1936, according to this report, the highest gas-oil ratio was 806 MCF per barrel as against 1,350 M.C.F. in 1938. They still had wells with no gas-oil ratio in 1936.

At page 30 of the 1937 report we find that in Moore County for October, 1936, the average was 50 MCF per barrel as against 29.9 in April, 1938. The highest gas-oil ratio in Moore County in October, 1936, was 1,776 MCF per barrel, as against 4,782 MCF in April, 1938.

This report shows that in October, 1936, the average gas-

oil ratio for the Osborne area was 26 MCF as against 3.4 in April, 1938—more than six times as much in 1936 as in 1938. The highest in October, 1936, was 245 MCF per barrel, as against 15 in 1938—more than fifteen times as much in 1936 as in 1938, and still there were wells in the Osborne area as well as in the other two areas which had no gas-oil ratio.

53 I do not know how much oil was produced from the wells which had no gas-oil ratio. I do not believe there is anything in that report that indicates the differentiation between the two. It gives the total gas produced, the total oil produced, and the ratio between the two. In arriving at my six trillion cubic feet to determine how much of the oil would be produced from wells having no gas-oil ratio, the only thing I can do is to use the average. I could not use the average in Moore County for the oil in Moore County because the amount of production in Moore County is comparatively small as compared with the total.

The average 6.1 or 6.6 was that way in 1937 or 1938 in the Panhandle proper, and in 1936 it was very little different from that. You ask if I do not know that it has been as high as 20,000 in the Panhandle proper in the past. It can vary over wide limits, there is no question about that; but the average remains pretty close for that period of time. I do not know it to be a fact that during the period of over 13 years that the field has been producing the average ratio has varied from 6,000 up to 20,000.

(May 23, 1939.)

In my former testimony I have referred to catchment basins. By catchment basin I mean a structure that is porous in nature, which is capped by an impervious layer of rock or limestone or anhydrites, that may serve as an area in which gas or oil may collect and not permeate vertically any further than that point. Applying this term, the entire vast reservoir is one catchment basin.

As I used that term, it is perfectly possible that down here in those little green bands which are shown on Exhibit 16 there are some small catchment basis in which free gas might have been trapped and which would produce with the oil when an oil well was producing from that area. I haven't any physical evidence of the fact that such free gas traps or catchment basins are in part of the formation that is below the level where this pink impinges

into the green on the going-down structure; but I think it would be a coincidence if there were none. As to whether those catchment basins are extensive in area or of comparatively small importance in dealing with the whole vast reservoir, I will say that in my opinion they would be small as compared to the total area of the dry gas area of the field. They might be, and probably are, of varying sizes or areas, but nothing to compare with the total area of this field. I would say that a portion of this casinghead gas about which I have been testifying, if not all of it, is in fact in solution in the oil. I would hesitate to say what portion is in the oil in absorption or solution. I would not say that 6,000 cubic feet is in solution per barrel of oil, and I would hesitate to say that 5,000 cubic feet is in solution. That is a question of the function of the pressure, probably, and other facts that would determine how much is there. It is a function of the pressure and of the quality of the oil and of the quality of the gas involved. I could not say whether there would be 5000, 4000, 3000, or 2000 absorbed in the oil. I would not say without making
54 a study of it. I think the proper way would be to make a study or research of the particular gas in hand.

There are 42 gallons in a barrel. If we take an empty barrel and make a catchment basin out of it and fill it with gas at 16.4 pounds per square inch, it would be the equivalent of 42 gallons. A gallon contains 731 cubic inches. Figuring on that basis, a barrel would contain 5.61 cubic feet—that is, at atmospheric pressure. If you have a barrel full of gas at 471 pounds pressure, the absolute pressure in the reservoir in the beginning, you will find that the barrel would contain 183.65 cubic feet at a pressure of 16.4. A barrel full of oil would hold less gas than an empty barrel. Then the gas which could be contained in a barrel of oil at that pressure would be something less than 183.65 cubic feet.

You have exhibited to me a report of investigations by the Department of Commerce, Bureau of Mines, Serial No. 2732, dated February, 1926, by D. W. Dowe and L. P. Calkin. I do not know either of those gentlemen. Apparently one of them has the title of engineer in charge of the Laramie field office, and the other, assistant petroleum chemist, Bureau of Mines. The Bureau of Mines is a government bureau, in the Department of Commerce.

Inserted between pages 4 and 5 of that bulletin is a figure or drawing showing different oils on numbered curves. Curve 5, is indicated by the notation on the bottom of this curve, is noted as natural gas in kerosene, 41 degrees, A.P.I. The next one is termed Curve 6, natural gas in California crude, 25 degrees, A.P.I. That appears to be the fourth curve from the bottom. Curve 7 is denoted as natural gas in Oklahoma crude, 21 degrees, A.P.I. That looks like the third from the bottom. Curve 8, natural gas in Wyoming crude, 36 degrees, A.P.I., is the first one reading from the bottom up. The figures along the bottom of the sheet apparently represent cubic feet of air or gas absorbed per barrel of oil in thirty inches of mercury. The figures along the left-hand margin represent pressure pounds per square inch gauge. I don't think that would correspond to wellhead pressure in comparing that to the situation in the Panhandle rather than absolute pressure, because the wellhead pressure is not the same as the pressure in the reservoir.

Applying that to arrive at the comparative figures for the Panhandle, you would have to determine the equivalent gauge pressure in the formation. That pressure depends on whether you mean initial pressure or whether you mean present or remaining pressure. If talking about original pressure, then the initial pressure in the field at the wellhead was 430 pounds gauge, and that would be equivalent to 471 absolute. In determining the gauge pressure in the reservoir you would subtract 14.4 rather than 13 because 14.4 is the atmospheric generally accepted at that point. That would correspond to a gauge pressure in the formation of approximately 456.6.

The gauge pressure in the reservoir originally in the Panhandle is just below the top of that checkered part
55 of the drawing there. Following that pressure of 456 across the drawing, we find that in the case of Curve 5, kerosene at 41 degrees A.P.I., that intersects the 460 line at approximately 94 cubic feet. Curve 6, representing California crude, intersects the line at approximately 89½ cubic feet per barrel, or probably closer to 90. Curve 7, which is natural gas in Oklahoma crude, intersects the 460 line at approximately 93 cubic feet per barrel; and the last one, Curve 8, which is Wyoming crude, if extended, would intersect the 460 line approximately at 102 cubic feet per barrel. With the under-

standing that you are taking parts of this report; that I am not familiar with the complete report; that I don't know whether the curves that you refer to represent the necessary saturation of gas in oil under those conditions; that you are asking me to interpret a portion of the report; and that it is your request, I will read from page 6 of this report the following:

"The oils used in this work consist of two refined oils and three characteristic crudes. The solubility of gas expressed in cubic feet per barrel for each oil is shown in Curves 4, 5, 6, 7 and 8 at the right of Figure 2. Curve 4 represents the solubility of the gas referred to previously as mineral seal oil, which has a gravity of 36 degrees, A.P.I. This determination, as well as all others shown in Figure 2, was made at a temperature of 70 degrees Fahrenheit, and gas volumes were calculated on the basis of 29.9 inches barometric pressure. The solubility increased with pressure, showing approximately 75 cubic feet per barrel at 460 pounds. Curve 5 represents solubility of the same gas in kerosene with a gravity of 41 degrees A.P.I. The solubility of the gas is much higher in kerosene than in mineral seal. At 396 pounds 80 cubic feet of gas is absorbed per barrel."

You inquire whether I noticed that the Bureau of Mines representatives referred to the oils shown in these figures as characteristic oils, and whether I know what they meant by characteristic oils. In the first place, they state definitely that the oil was from different locations, including California and Wyoming. Those are the two crudes. What was in their mind when they characterized that as characteristic oils, I can only guess. I think the best evidence would be the parties who prepared that. There are three crudes mentioned there: natural gas in California crude, natural gas in Oklahoma crude, and in Wyoming crude. Those three do not go up exactly together. Curve 6, which represents California crude, is the uppermost curve, which has the smallest quantity of gas absorbed of the crudes. No. 8, which is the Wyoming crude, is the lowest curve. Oklahoma crude, No. 7, is closer to the California crude than it is to the Wyoming crude.

I do not believe that crudes from the Texas Panhandle are identical with either one or the other. It would be a coincidence if it were; but I do not think it would vary

very widely. I would expect an analysis of the Panhandle crude to take approximately the same point as these crudes reflect here as to their solubility. I don't think it would vary a great deal. It would probably be within
56 a reasonable range. Where it would be, I don't think one could say without conducting comparable and similar experiments with crudes from that field to have the thing exact. I don't know. You haven't anything in that paper that I can see on Texas crude.

I could only guess as to whether I would expect an analysis of Texas crude to show the figures to be somewhere between the range of 89 to 102, and I am not guessing on the record. I don't know that I have ever seen the results of experiments or tests on the Panhandle crude so as to see whether it is of lower solubility than ordinary crude oils. I think that it is a paraffine oil. (Objection by Commission Counsel.)

You ask if in this 6,000 cubic feet per barrel which I have defined as being casinghead gas I would expect not to exceed 100 cubic feet of that in each barrel in absorption. I would not expect that because the chart just referred to referred to 102 in one place. If the Texas crude corresponds in solubility of gas with the particular crude that shows the degree of absorption in that curve, it may be 102, but it will not be much above 100, but if it turns out that this is a crude of lower solubility than the others, then the quantity of gas absorbed in the Panhandle crude would obviously be less.

If the oil had a higher temperature than 70 degrees Fahrenheit, you would probably have less gas absorbed. This is due to the effect on the solubility of an increase in temperature. I would say that if it turned out that the Panhandle crude has a higher temperature than 70 degrees, I would not say that the quantity of gas absorbed in a barrel of oil to be less than that shown by these curves. I would say that any increase in temperature would have the effect of reducing to a certain extent the solubility of natural gas in crude. I would not make the statement that it would be less than anything shown on those curves. If it be assumed that the solubility of the Panhandle crude as compared with the three crudes portrayed by those curves is comparable or less and that the temperature in the Panhandle reservoir is more than 70 degrees Fahrenheit, then I would say that the quantity

of gas absorbed in a barrel of oil would be comparable or less than those shown in those curves the same way as referred to in each of the curves.

My information is that the temperature of the reservoir in the Panhandle is about 90 degrees. I would have to study the report in order to correct a figure based on 70 degrees to one based on 90 degrees.

You assume for the purposes of a few questions that there is at least 100 cubic feet of gas in each barrel of oil in the large reservoir in the Panhandle, and inquire how much of the 6,000 feet average casinghead gas production would be found in the catchment basins about which I was talking. Before I answer that question I will state that while I haven't had an opportunity to study that report from which you have been quoting, I do not know that the gas in cubic feet per barrel is listed at 30 inches of mercury. When you are talking about gas in the reservoir of the Panhandle field, you are talking
57 about gas in something different than 30 inches of mercury. It is the difference between 14 pounds and 471 pounds. As to whether the difference would be to reduce the absorption and whether the conditions in the Panhandle as compared with the 30 inches of mercury would give a result showing less absorption in the Panhandle reservoir than the 30 inches of mercury, I would have to study and experiment and find out. (Objection by Commission Counsel overruled.)

You assume for the purposes of your question that the absorption of Panhandle oil is 100 cubic feet per barrel, and ask me where the remaining 5,900 cubic feet of the 6,000 cubic feet included in my estimates of the reserves in the oil producing formations is or was. My reply is that the figures used in my estimates took cognizance of the fact that in its annual report the Railroad Commission of Texas had a gas-oil ratio approximately 6,000 cubic feet per barrel of casing head gas for each barrel of oil produced. But yesterday on cross-examination I believe that you brought out the point that in the 1936 or 1937 report the average amount showed 6.6 MCF per barrel. Now, on that basis I estimated—and I took the figure at face value as reported in the official report of the Railroad Commission's document—that the average barrel of oil produced also produced approximately 6MCF of gas. In my cross-examination by you yesterday I testified, and

again this morning; that a portion of that 6 MCF of gas undoubtedly was gas produced that had been dissolved in the oil. Now, a portion of it I believe comes from that source. I believe that another portion of it very probably comes from gas in the gaseous stage or vapor stage that occurs in the catchment basin with the oil. I think also that probably some of that gas enters into the well bore from other portions of the porous producing formation; but where that gas comes from that enters the well bore and is produced up through the stream with the oil I question very much whether there is anybody that can say. It comes from the formation. This we know, that it comes out of the casinghead well. We know that it traverses the casing and comes up; but what portion of the formation it comes from, I don't know and I question whether anyone else does.

As to whether it came out of those bands or producing formations colored in pink or red or whether it came out of the catchment basins down here in the green, all I know is that it came out of the well with the oil. I cannot testify at this time that I know that it is commonly accepted in the Panhandle, by the Railroad Commission of Texas, and by the geologists with whom I have talked, and the producers with whom I have talked, that practically all of the gas comes out of these red bands or dry gas producing formations, or free gas producing formations. I cannot sit here and testify to the fact that I know it is a matter of common knowledge in Texas among the Railroad Commission authorities as well as those who are engaged in the business in the field that the gas, substantially all of it, comes out of formations which are productive of free gas and that it does not come out of the area which is colored in green just below the free gas producing formation, because I don't know that.

58 In all my estimates of the reserves down there I have assumed that the gas produced with the oil came out from somewhere in the formation and was produced with the oil, and it is characterized as casinghead gas; also a portion of the casinghead gas came from the gas absorbed in oil. I think that is a reasonable assumption. I also assumed that a portion of that gas was in there with the oil, very probably at the start, at least, in the vapor phase here as gas.

When I got through estimating the original content of gas in the formations which produce free gas, I added six

trillion cubic feet to my total. As to whether I assumed that all of that six trillion cubic feet was originally down there, either in solution or in the catchment basins within the portion which did not produce free gas and was not included in my estimate of free gas in the Panhandle, I will state that I made my estimates on a per acre basis. I used the area of the field which is known as "gas acres," and spoken of in the Commission report as "gas acres." I read yesterday a portion of that report that indicated that some 250,000 acres in that field were characterized as oil acreage; that there was an overlapping of approximately 40%, as I remember—an overlapping between the gas acreage and the oil acreage.

It is my understanding that there is a portion of that field which produces oil and possibly some gas, casinghead, that is included in the gas acreage. So that, unless in any estimate that oil acreage, or at least that part of it which produces casinghead gas, is included—in other words, if that is disregarded and an estimate made of the gas content in this field of the gas acreage alone, it is my opinion in arriving at any estimate of the life of this field one must either include all of the gas source if you include all of the gas withdrawals or if you exclude certain portions of the source, the casinghead, let us say, you exclude the casinghead altogether, then it is only consistent to exclude the casinghead withdrawals as well as the casinghead reserves. Now, where that gas comes from, whether it is possible to draw a fine and definite distinction between either the casinghead in place or the casinghead withdrawals, is a question.

In estimating the reserves underlying the Panhandle gas field I first estimated the per acre reserves in what is termed the gas acres. It might not be strictly true that this area is all given some color in Exhibit 12. That exhibit is a pressure map that indicates for all portions of the field that are shown in color the results of the pressure surveys of the Texas Commission. Some of those areas close to the northwest flank, some of which are colored and some of which are not colored, contain substantial portions of the area of the field that is known, or at least designated in the Railroad Commission's report, as oil acreage. The part, according to their designation, which is underlaid with free gas is, in round numbers, 1,475,000 acres. You ask if of this 1,475,000 acres which the Railroad Commission has classified as gas bearing land, approximately 100,000 acres

also produce oil—approximately 40% of the entire oil producing area. I answer that by quoting from the annual report of the Railroad Commission dated July, 1938,
59 in which, referring to the Panhandle oil and gas field, it is said:

"It is composed of 1,076,423 acres which produce sweet gas; 398,901 acres which produce sour gas."

Now, the sum of those two is 1,475,324 acres, which produce sweet and sour gas. Then they go on to say:

"And a proven or semi-proven oil producing area of approximately 250,000 acres."

Then they say, "approximately 40% of the oil producing acreage is included in the gas area," so that, as you state, approximately 100,000 acres of the proven or semi-proven oil producing area underlies or is within the 1,475,000 acres of gas.

I first made an estimate of the gas in the gas bearing formations underlying that 1,475,000 acres and then added to that figure six trillion cubic feet, which I said was casing-head gas and gas in the oil area. You state that you are trying to find out where that six trillion cubic feet was in the formation. I think I stated that a portion of it was undoubtedly dissolved in the oil itself. I don't know how much of that is dissolved in the oil. I would hesitate to say whether it is approximately 100 cubic feet per barrel or more or less than that until I had an opportunity, either by research or survey or experiment or test, to determine the solubility of Panhandle crude.

You state that it would have to be less than 183 cubic feet. If you will pardon me, let us not get confused on this thing. When you refer to 183 cubic feet you refer to the volumetric content of a barrel at 471 pounds pressure, filled with gas, and of course that would be far more than 183 cubic feet on the basis of 16.4. I was willing to accept your statement that a barrel contains 5.61 cubic feet. Using my slide rule, taking 42 gallons in a barrel and multiplying that by 231 cubic inches per gallon, and dividing the product by 1,782 cubic inches per cubic foot, I get 5.61 cubic feet per barrel. Adjusting that to the number of cubic feet contained in a barrel at 471 pounds pressure absolute, on a pressure base of 16.4, I get about 161 cubic feet. I have testified earlier that if you fill that barrel with oil you get less gas in the barrel than you would if you didn't have any oil in there. It would unquestionably be less.

You assume that there could not be more than 161 cubic

feet in absorption and ask me where the remaining 5,839 cubic feet of gas, which comes out with each barrel of oil according to the figures I have used, was in the formation at the time the reservoir wis discovered when it had an initial pressure of 471 pounds. My answer is that it was in the formation and undoubtedly was in that section of the formation from which the oil came.

60 You ask if I think it could have been drained off there from these areas out to the southwest and gotten into the oil bearing area through drainage from areas that originally bore gas only. There undoubtedly is drainage in that field, due to the fact that there is a porous formation practically throughout, and due to this fact that the initial pressure in that field was so uniform, being approximately 430 pounds. Now where that gas came from, how it gets in there, or how it got in there, I do not know, but in any event the record in the Commission's report indicated that the average is the production of 6 MCF per barrel of oil. Now, as to where that gas came from and how it got in those oil measures, I am not prepared to say. One could speculate many things or one could say that that gas did drain in there from the dry gas area, all of it. That would be one hypothesis and one theory, but it is my opinion that a substantial amount of gas must have been in those oil measures from which the oil was produced at the inception.

I was talking about original reserves at the time I used the six trillion estimate. I did not go into the gas-oil ratios, but for the one month of April, 1938, when I figured out that six trillion, which I added to the figures that I brought in as my estimate of the content of the gas bearing formation itself. I had only the figure for the month of April, 1938. That figure applied as an average figure in the greater portion of the reservoir in what is known as the Panhandle proper—in the largest zone designated by the Railroad Commission. I do not know what I would have found the average gas-oil ratio throughout the history of the field to be had I gone into it; but I assume very probably the gas-oil ratio during the earlier years of the field might have been substantially higher than the present average. I assume that because it has been so in other fields.

After I had figured the reserves of gas contained in the formations, typified on Exhibit 16 by bands or ribbons painted red throughout that field, where situations were comparable, though the contours of the granite mountain

and the other things flanked on it would have been different had I made my cross section somewhere else. There would also have been red bands or porous bands bearing dry gas only throughout the reservoir, and I made my estimates of the gas which was contained in the gas bearing part of the formation and arrived at a figure of 23 trillion cubic feet. I don't know how the gas got there and I do not think anybody does.

You state that you want me to tell where it was resting in the formation—that six trillion cubic feet which I added to the 23 trillion—at the time the field was discovered. In answer to your question, which I understand, the reason I included that figure for casinghead gas was because I did not want to leave out entirely and disregard that portion of the natural gas reserves in this field. The natural gas reserves in this field, in my opinion, consist of two things: first of all gas includes dry gas or, well, let us call it dry gas and casinghead gas. In my opinion, if we take the total
61 withdrawals from the field and include in the total withdrawals both dry gas and casinghead gas we must, to be consistent, give whatever is a reasonable consideration of the original casinghead gas reserve. In my opinion, there is no question but what some of the original gas in place in this field was of that nature, namely, casinghead gas. In that case it was in close proximity to the oil, and in answer to your question I will say that I took the position that the gas that is produced as casinghead gas there is that gas, and was in place in proximity with the oil, some of it dissolved in the oil and some of it in the oil measures. I do not say that there is no migration of gas in this field, because in my opinion that would not be so.

I do not think that I counted twice that part of the six trillion cubic feet which has migrated from the gas producing formations which did not produce oil over to the oil wells and was produced and called casinghead gas, because there is a counterbalancing factor in that thing. The area that we call gas acres, this area that I have used as gas acres, does not include certain of the producing area in that field which is not colored on the map, and in estimating the total dry gas reserves I have not included the other area. I have included all of it that bears free gas, the whole 1,475,324 acres that is in the dry gas producing area, and I put the 23 trillion that I estimated in the dry gas area in the dry gas bearing formations.

You state that if six trillion is added to that, I necessarily must place that six trillion somewhere else, and ask where I put it. Let us say we put it in the oil measures. What I mean by that is those formations, portions of those formations that are producing oil. That part of the formation that is producing oil I call an oil measure, and in making my estimate I necessarily put that gas in the oil formations.

You refer to little bumps or cones or raised places in the fold itself which I referred to as catchment basins. Of course those formations are irregular and you would expect to find gas in them. You ask whether I have ever seen the log of a single well drilled in the Panhandle that ran into one of those catchment basins in the oil producing formations. I do not know where you would find it in the log. I have seen well logs in the Panhandle and have seen references to as many as eight or ten gas bearing ribbons or bands or formations before they reach the oil level. The logs include many things, including the types of formations passed through, water encountered, gas streaks, shale bodies, lime, dolomite, and indications of oil. Everything they pass through is supposed to be indicated on that log. I doubt very much that any catchment basin of free gas below the top of the oil level would be recorded in there. I think perhaps it would be easy to pass through such a thing and not record it in a log; but I cannot conceive that it is impossible that these conditions do exist. In other words, the formations are irregular, and in the very nature of occurrences of oil and gas it seems to me reasonable that there would be oil or at least gas entrapped with the oil at
62 certain places. As to how much of a gas bearing formation would ordinarily be encountered before it was reflected in a log, it depends upon who makes up the log, whether it is a driller's log, whether it is an electrical survey, or what it is. You would note it in an electrical survey or Schlumberger log.

I say that a part of the gas in the Panhandle is in these little pockets and catchment basins. I say it is in the formation, part of it in solution with the oil, part of it in these catchment basins. Nevertheless, it is in those formations.

The Commission's report uses 250,000 acres as being in the oil field. A great deal of the 250,000 acres is, as shown by the map, blank, indicating that it did not produce oil. Wide areas are found between the pools of oil—the oil producing wells being located in clusters and out over the

250,000 acres. I do not know what is down deeper than they have gone in those intervening areas. Some logs indicate salt water is down below those areas. If they are drilled to sea level they indicate one of two things: either that they hit the top of that granite mountain or that they hit salt water.

I have estimated the production of oil from the 250,000 acres to be one billion barrels. I obtained that estimate of one billion barrels from the July, 1938, report of the Railroad Commission of Texas. On page 31 of that report I find the following:

"Oil production under proration has steadily increased in the field and has now reached a level of over two million barrels per month. Over one million barrels of this oil is being refined monthly by the eight refineries located in the immediate area. All remaining oil is transported by pipeline to distant points in Texas and Oklahoma. To date the field has produced in excess of 318,000,000 barrels of oil. Table 9 has been prepared showing the cumulative production prior to August, 1935, as a total, and all subsequent production is shown by months. Some geologists predict an ultimate recovery of one billion barrels for the Panhandle. On this basis there still remains 680,000,000 barrels of recoverable oil in the reservoir."

You inquire whether the presence of gas pressure, the pressure exerted by gas in the formation in the oil and in the vicinity of the oil, has anything to do with the production of oil to the well and from the well. It is generally conceded that in the reservoirs that contain both gas and oil under pressure that the gas pressure or the pressure existing in the gas and thence transferred to the oil is very probably the motivating force that moves the oil through the formation to the well bore and up out of the well. That, of course, is true in connection with the flowing of wells by their own pressure. It does have largely to do with the total amount of production.

63 The report referred to does not say when the prediction was made or what those same geologists thought about it at any later time. It just simply states that some geologists have predicted that there were a billion barrels of recoverable oil, and that on this basis there still remains 680,000,000 barrels of recoverable oil in this reservoir.

According to my original estimates there were in that 250,000 acres six trillion cubic feet of natural gas, either in absorption in the oil or in catchment basins in the oil pro-

ducing part of the formation. If it is assumed that 161 cubic feet of that gas was in absorption in each barrel of oil, that would represent 161 billion cubic feet of gas. Subtracting that from six trillion leaves 5,839,000,000,000 which was in the formation. I would not say it was in the catchment basins. It was both in absorption with the oil and in catchment basins. You state that we took off 161 billion for absorption in the oil. The rest of it, 5,839,000,000,000 cubic feet, would have to be in the oil bearing part of the formation.

You ask me to figure what sand thickness would be required in that 250,000 acres to include 5,839,000,000,000 cubic feet of gas, at 16.4 pounds. The first thing we have to do is to get that back into figure at the original pressure, 471 pounds absolute. We have got 250,000 acres. The total amount of gas, 5,839,000,000,000, at 16.4 pounds would be 250,000 acres times some assumed porosity. You have got to assume some porosity. You state that we are going to talk about porosity a little later and ask me to tell you what the average distribution of that 5,839,000,000,000 cubic feet of gas is down there under the 250,000 acres. It is about 21,500,000 cubic feet of gas under each acre on the average.

In arriving at my 23 trillion estimate of the gas where there was no oil in the way of it, I used an average per acre of 16 million. I used a very conservative thickness of formation in my estimate of dry gas. I used a 70-foot thickness, as I recall. I used 16 million cubic feet per acre as an average over the entire 1,475,000 acres, and it is very probable that in certain acres there is very much more than 16 million cubic feet under any individual acre. There would have to be if 16 million is an average.

We are also talking about averages over the 250,000 acres; but there we are talking about 250,000 acres as against nearly a million and a half.

You state that you want to know how much sand thickness we would have to have making up those catchment basins in the oil field areas in order to get that much gas. Let us not assume that those are all in those catchment basins. Those gases may be somewhere in those measures, and I have made no statement here to the effect that all of the gas was inside catchment basins. I did not put it there the other day in making out my estimate. I said that the gas I estimated was in the oil as casinghead gas, was in the oil measures. Part of it was dissolved in the oil, part of it in

those catchment basins, and part of it in the producing measures.

64 You state that after deducting the 161 billion, which is the maximum that could be in absorption, we have 5,839,000,000,000 down there in catchment basins or in oil measures, and ask me what would have to be the average sand thickness of that part of the oil producing formation which I call catchment basins plus that part where the free gas is in the oil measures, whether in catchment basins or not. We will take it on a per acre basis, using the figure of 23.3 million cubic feet per acre and using a porosity of 20%. The average thickness per acre of the sand at that porosity would be 93 feet. I used the figure of 20% porosity for the reason that that is the figure I used in the estimate of the dry gas area and that is the figure which we have been talking about.

I have already testified that I used 70 feet as the average thickness of all the gas pays that are found throughout the gas area. According to the computations I have made, there is a greater thickness of pay formation yielding dry gas down here where the oil is than there is up where there is no oil, assuming, of course, that it has the same porosity. The porosity figure enters into it very directly. If you use a different porosity—let us say you used a figure of twice the porosity in that particular part of the formation, you would then halve that thickness. It is directly proportional. I have no reason to use twice the porosity. By the same token it may not be consistent to use the same porosity. In other words, it might be different. As to whether it is as apt to be a lower porosity as a higher, that would depend on the type of formation which you are considering. It might be higher or it might be lower, and I have no information on which to say that it might be different, except perhaps that some of the oil, probably a substantial portion of it, is in the granite wash, as you have shown on your chart.

Some of the gas is also in the granite wash, and you have both granite wash and dolomite formation yielding oil and also yielding gas, but probably the greater portion of the gas comes from the dolomite. A great deal of the oil now being produced comes also from the dolomite. The East field is producing gas almost exclusively from the granite wash. By East field is meant that portion lying east of a line running approximately through Gray County, north

and south, and pictured on Exhibit 17 by a heavy red line. The area east of that line is known as the East field.

It is true that nearly all of the production in the East field of gas is from the granite wash. Of course the quantity of gas produced there is substantially less than is produced in the West field. As shown by the figures read into the record yesterday, it is a fact that over where the granite wash is, the gas-oil ratio is lower than it is in the dolomite. Osborne is over in the East field and has a lower gas-oil ratio. Up in Moore County where the production is exclusively from the dolomite, we find a very high gas-oil ratio as compared with the central part of the field commonly called the Panhandle proper.

I do not know the span between the lower part of the
65 oil bearing formation and the upper part of that formation from the standpoint of altitude. I do not know what distance it is perpendicularly between the place where free gas plays out and the oil is encountered and the bottom of the oil producing formation. I presume that varies with the field.

Taking the field as a whole, I do not know what the distance is between the water level and the level at which the gas comes out of the formation in a free state. In other words, I am not informed as to the distance between the water level or sea level as portrayed on Exhibit 16 and the point where oil is no longer found but where free gas is found in the various formations.

As stated, I used two methods of computing the reserves of dry gas in the reservoir. One is called the reservoir porosity method and the other the pressure decline method. The pressure decline method is commonly used in cases where a reservoir has been developed for a sufficient period of time to have experienced a reduction in pressure which can be compared with a certain withdrawal. In other words, where you have a certain volumetric withdrawal and a corresponding reduction in pressure in the reservoir. In applying this formula you determine first the amount of withdrawal and the pounds drop in pressure, and then using the original or virgin pressures and abandonment pressures, determine on that basis what would be the amount of the original reserve. In my computation of the original reserve I used both gauge pressure and absolute pressure. I started with an original virgin wellhead gauge pressure of 430 pounds per square inch. From that I com-

puted what the original or virgin pressure would be on an absolute basis and arrived at 471 pounds. The gauge pressure corresponding to that would be the difference between 471 and 14.4, or approximately 457.

I then obtained a figure furnished by the Railroad Commission of Texas which it defines as the weighted average pressure in that field, which, as I remember it, was approximately 337 pounds per square inch wellhead pressure. I reduced that to reservoir pressure, and arrived at 373 pounds, which I subtracted from 471 pounds, and got an answer of 98.

I then assumed that all the gas that has been produced from that reservoir, seven trillion and some billion cubic feet, has pulled the weighted average pressure down by 98 pounds from what it was to begin with. I determined the withdrawals per pound drop by dividing the total amount of estimated dry gas produced by 98. That gave me a figure of 51 billion and some odd million cubic feet per pound drop. I then multiplied that by 431, which is the difference between the original absolute pressure in the reservoir and the ultimate remaining pressure in the reservoir to 25 pound abandonment pressure gauge at the wellhead, and arrived at my estimate of the gas contained in the dry gas producing part of the formation as being approximately 22,130,000,000 M. C. F. I added to that as casinghead gas six trillion cubic feet just as I did in the method of computation based on reservoir porosity.

66 The figure I used as the amount of gas produced from the field in the past was that furnished to me by Mr. Peterson. It included all the gas which had been produced from the field to the date of his then computation, which I believe was July 31, 1938. Mr. Peterson is geologist for Texoma. At that time I understood that that was his best estimate of the total withdrawals from the field to date. I also found that it was commonly accepted among the geological fraternity and others interested in the field down there. They usually talk about seven trillion cubic feet. That is very close.

Referring to Exhibit 13, you have called to my attention several purple or reddish looking lines which run around the general border of the field, from a mile to several miles inside the heavy black lines that mark the boundary of the field, and have pointed out that in the eastern portion those reddish or purple lines enclose similar areas, and one, apparently a large area, is in what is commonly referred

to as the East Panhandle field. I know what those red lines purport to set out. They purport to enclose that portion of the whole field which in Mr. Peterson's judgment was the best portion of the field. He stated that his judgment was based on the fact that that was the portion of the field in which wells have potentials of five million cubic feet or more. He stated that the areas outside those reddish lines were those in which the wells had less than five million cubic feet potential. I know how large the wells through the more productive portions of the field were as shown in the Railroad Commission's report for the year 1938. They ranged from five million cubic feet per day to about 78 million. As a matter of fact I know that originally when all of the pressure was there, wells were drilled in this area which made more than 100 million cubic feet of gas per day; but I am talking now of the tests that were made in 1938.

You ask me if Mr. Peterson told me that in the area outside of these reddish lines, but still within the reservoir, no well made as much originally or was capable of making as much while at its virgin pressure as five million cubic feet. I don't know that that statement was made in just that way. I understood from Mr. Peterson, in talking with him about his estimates and about this line, that that portion of the area outside of that purple line did not contain wells whose potential was in excess of five million cubic feet per day. I presume that he meant initially, I don't know. I don't remember that he so stated. I believe he told me that he based his judgment on actual production figures of those wells that had been drilled within that area. I was convinced that he had made a very careful study of it, and I have no reason to doubt that the well in its initial stage—without treatment—we discussed this treatment of acidization and the use of explosives in the well—and I believe Mr. Peterson said that in combing over the records in that field he tried to get and tried to base his conclusion upon the original conditions there prior to any treatment; so that as I understood it, all of his conclusions were reached or attempted to be reached on the natural conditions in the wells. It is very possible, however, that many of those wells could be treated so as to increase their flow.

I think Mr. Peterson, in stating that the wells inside the reddish line made in excess of 5 million cubic feet a day, was talking about all wells in their natural condition before they were treated or acidized. For purposes of simple

comparison, therefore, between the areas and the wells in their natural condition, it does not matter whether you think of it as treated or not treated. But it does not limit those wells in the outer area from producing more than 5 million cubic feet per day after treatment.

67 The wells producing not more than five million ranged downward as to productivity. They ranged all the way from a little show of gas to five million. It does not put any more gas in the area to acidize it or apply explosives.

There is no doubt in my mind but that the greater portion of the gas originally in place was included within those reddish colored lines, and I believe as you get away from these reddish colored lines toward the area running in the northwesterly direction, approximately along the gathering lines of Texoma, you get in the heavier production and the better class of production.

You inquire whether the greater portion of gas has been from the more productive areas in the field or from the field as a whole. Of course, all of the production has naturally come from producing wells and that production has come from those areas in which the wells have been successfully completed, so that as far as production is concerned, the greater portion has come from this portion of the field where there are existing wells, and those wells are included in the reddish lines. They are largely up through the central portion of the area enclosed within the reddish lines and to the north of that within the West field.

Getting down to the East field, we find there has also been production there. The area is smaller and the production has not been so large. More wells have been drilled per 100 acres out over that area which is enclosed within the reddish lines than you find in the western portion of the field—a more general distribution. The total area of the field is substantially less than the west field, and it is probably true that the wells per acre, taking the whole area of the field, is greater than it is on the west field.

On the map I see little stars scattered over the areas, grouped closely in places and in other places appearing infrequently. They represent gas wells where they are represented with little diameters extending out from a circle. Where they are solid black dots I understand they are supposed to represent oil wells. I believe it is correct that in the east field the areas enclosed within the reddish

lines have been more drilled up as a whole than the areas in the west field.

I don't know for sure that the locations where the wells have been drilled may or may not prove to be the most productive portion of the field. There are many very productive wells, other wells of high potentials.

You inquire whether the wells get smaller or larger as you leave the area in the central portion the field enclosed within red lines and go southward or southwest. I think it is natural to expect that the wells which have been brought in are of a lower potential as you leave the central axis and go toward the southwest. The wells are pretty well included in what is in my opinion the more productive part of the field. Of course, there is a great deal of land and area to the south of that axis that is very productive—for instance, the leases of Canadian River and others.

68 You inquire whether they have produced their requirements from the more productive wells to the exclusion of those which are down in the less productive areas. I think it is perfectly natural that a producing company should attempt to produce gas from its properties where the production will cost less per MCF than in other parts. I think that is just ordinary economy; and furthermore, in those portions of the field which can be reached by a trunk line.

You inquire whether it necessarily follows that all of the gas which is produced from an existing well was produced from the immediate vicinity of that well, as I find conditions down in the Panhandle. All the gas that is produced from a well is produced from the immediate vicinity of it. There may be some migration through the measures. My whole theory in connection with that field is that it is interconnected, and due to the fact that the original virgin pressure was pretty uniform over the field generally speaking, the producing horizons underlying the field must be connected. How much, or rather what rate of migration would take place, had taken place, or will take place, depends on the resistance to that migration and the differential in pressures, and these maps which you have, Exhibits 12 and 17, both being rock pressure maps, and so designated, indicate a lower rock pressure in the northeast slope or north flank of this field, with gradually increasing pressures as you approach the southwest flank of the field. In that northwest area I know that there are substantial amounts of gas being produced, sour gas largely, that had to be used for

the manufacture of carbon black; but it is apparent to me that it is having its effect on the field.

I have already stated that the main production from gas wells has been through the central portion of the area enclosed within the reddish lines in the western part of the field, commonly called the West Panhandle field. It is my idea that the pressures reflected in the areas where these walls have been producing as gas wells was largely attributable to the production from those wells alone.

You inquire whether I think most of the gas which has come out of the formations in the vicinity of dry gas wells has been produced from the dry gas wells. I don't know as I just get your question there. Of course, all of the gas which has been produced has been produced from those wells. In the production of gas from the reservoir that production has had a very material effect in reducing the original pressure.

You call my attention to an area shown on Exhibit 17 colored in dark brown, which the legend says indicates pressures from 360 to 380 as against the original 430. You point out a number of sections thus colored on which no wells appear but where wells are shown around it. It is my thought that that area has had its pressures reduced as a result of the withdrawal of gas through those wells right around it to whatever extent production has come from those wells. Other wells more distant from any particular point would also pull down those pressures, to my way of thinking. I would not make the statement that I would not expect any of the gas to have moved over to where
69 there are both gas and oil wells and where the oil wells have been producing for the past twelve or thirteen years. In other words, I would not say that no gas has moved in there. I realize the fact that gas might migrate in a porous structure that is inter-connected. That is common sense.

My views are these: in that low pressure area that we referred to there are wells which are producing oil, there are wells in there which are producing gas, there are wells which are producing casinghead gas with oil, and there are wells which are producing just gas. However, all of the gas that is produced in that low pressure area, including dry gas and casinghead gas, is what is known as sour gas. That sour gas cannot be used in large quantity for pipeline purposes. Hence in this field it is used largely for burning under carbon black burners in the production of

carbon black. The amount thus used is, according to the Texas Railroad Commission's 1938 report, approximately 45% of it, if I remember correctly—that is, of the total gas produced in this field for that one purpose; so there is a use and withdrawal of sour gas from the northwest flank of the field which is used for carbon black. That withdrawal, which is very substantial and is greater than for any other one purpose for which gas is withdrawn at the present time from that field, is bound to have its effect upon the pressures in the field. In my opinion, that use and that withdrawal of the sour gas is what is causing these changes in pressure in these pressure areas. In this discussion I have been referring to Exhibit 17.

Of the gas which I said had been produced as sour gas from the oil fields, the greater portion is in the West field.

On page 2 of the annual report of the Railroad Commission of Texas, dated July, 1938, under the caption "Development," I read the following:

"The oil wells in the various pools in the field were as a general rule drilled through one or more gas containing strata before entering the oil horizon. In many instances the wells were completed in such a manner that gas from the gas strata was produced along with the oil and gas from the lower oil strata. As a result, a quantity estimated to be in excess of two trillion cubic feet, a large part of which came from the upper gas strata and was produced with the oil, has been wasted into the air."

I think it is true that the production from the wells in the highly productive area up through the central portion of the area enclosed in the reddish lines in the West field is not all of the gas which has been depleted from the formations originally under that portion of the field. In other words, all of the gas that is missing from the better portions of this field has not come through the wells in those portions, but part has gone over and been produced in the northeast in the low gas producing area, including sour gas and low producing areas.

The higher pressures are indicated on Exhibits 12 and 15 by the yellow color. Those are pressures which are still in excess of 400 pounds.

I think the first gas production in the Texas Panhandle was from what is known as the John Ray Dome over in northern Potter County. It is my impression that it was there that gas was first produced and carried away through

a pipeline for fuel purposes to the city of Amarillo, and that area has been producing gas and supplying the city of Amarillo since, I believe, about 1919. The well was completed in December, 1918, and the pipeline was built the following year. After twenty years of production for pipeline purposes, the pressure from which that gas is being produced to supply the city of Amarillo has gone down to where it is around 380 pounds in that little area.

You ask me whether with the pressures in that area being so near what they were to begin with—the pressures of the three wells in that little area being 388, 395 and 396—indicates that the heavy depletion of gas in those areas where you have found the pressures have gone down materially must be attributed to something other than gas line purposes. I would say if there were any more such areas in the field the pressure would depend entirely on the withdrawals. There may be a uniform pressure over the entire field and a sudden reduction must be due to the withdrawal of gas. The fact that the gas pressures in and around the John Ray Dome in northern Potter County have been reduced only slightly from the original pressure is due in my opinion to the fact that the amounts of gas withdrawn to serve the city of Amarillo and vicinity have been relatively small. Up in the area where the pipelines are producing heavily, you will find a greater pressure reduction than that which obtains down here where they have not produced for gas line purposes for twenty years. The area has certainly experienced a withdrawal.

In northwestern Hutchinson County we find from Exhibits 12 and 17 that a very substantial portion of the initial average pressure still exists. Another yellow or high pressure area is in southwestern Moore County and extends northeasterly with the west line of the field up toward the town of Dumas. That group is partly included and partly excluded by the red lines on the particular map at which you are pointing. It has a red line which indicates sweet and sour, and you mean the purplish line. All of this area from a point immediately west of Dumas, where the field plays out, on around through the southeastern part of Hartley County, across the south line of this little field, across Potter County, we find an area of small productivity, a high pressure area. That pressure area also extends over into the more desirable acreage or more productive area.

Coming to a place south of Pampa and a little to its
71 west, we find that in that portion of the field generally south of Pampa, which might be termed a peninsula, the pressure is 400 pounds or better, according to these maps. The contour of these reddish lines indicates that a large portion of that is in the area of low productivity. Going to the eastward, the area right south of the irregularly shaped area surrounded by dark lines near the middle of Gray County, we find a pressure condition indicating 350 to 400 pounds and part of it 400 pounds or better.

My understanding is that the area within the white on all of the three exhibits Nos. 12, 13 and 17 represents a territory that is apparently barren of either oil or gas, due to some reason. Those areas immediately to the southwest connecting up with this peninsula have pressures running from 350 up to original pressure. I assume they are areas of small productivity. They are outside the red lines with the exception of the small area in the middle of the peninsula. Going to the east we find one more small area near the eastern tip of the field which has a pressure of 400 pounds and above. My understanding is that the wells in that area near the town of Shamrock are wells with lower potentials rather than the higher ones.

In averaging pressures in the field for the purpose of arriving at the weighted average pressure in the field, which the Railroad Commission has declared to be 337 pounds per square inch, there is no doubt but that there are averaged into that figure all of these low productive areas. I think I have Mr. Peterson's figure as to the extent of those areas which have wells producing five million cubic feet per day or less. I think he divided it between the so-called preferential area and the area not so preferential. The acreage in what he termed the marginal gas area in the entire field is in his judgment 432,967 acres, and the area included in what he terms the best commercial gas area amounts to 1,033,970 acres. His total, however, does not exactly correspond to the total area set forth as the producing area by the Texas Railroad Commission. It is a little bit less. The total area or the sum of his best commercial gas and marginal areas amounts to 1,466,937 acres.

It is largely true that a large proportion of that marginal acreage or acreage of low productivity is found in areas of the highest present existing pressures, except in the

East field. The main part of that area where there is low productivity is in pressure areas between 300 and 400 pounds.

In making my computation of reserves based on declines in pressure I included all of the acreage set forth as productive acreage by the Texas Commission, namely 1,475,324 acres, and accepted their figures showing the weighted average over the whole field instead of just that part that is included within the read area.

You asked whether I get a distorted picture of the pressures over the field in relation to the productive qualities of the field if I average that 432,000 acres, with its prevailing higher pressures, into the average for the whole field. In my opinion what you get is a weighted average pressure over the whole acreage in the field, and if you consider the whole field as one reservoir, that is, the gas portion of it, I think that in order to secure or determine the present weighted average pressure in that field one would have to proceed in the manner in which the Commission proceeded. I believe that the answer there, the 337.66, or whatever the average wellhead pressure was that they determined, is just that, the weighted average over the total gas acres in the field, regardless of whether or not some of those acres included are of high potential productivity.

72

You ask me if, when I applied that figure which includes the area of high pressure but low productivity, that would not give me a distorted picture of the pressures in their relation to the productive areas in the field or areas of most productivity, and my answer is no.

There is no doubt but what the pressures set forth in Exhibit 17 are lower in the central portion of the field where the greater number of wells exist today, and the pressures in the central axis are lower than they are on the western edge. I don't subscribe entirely to your observation that those areas are where the heavy production has always been and where the original reserves were heavy. I think you are assuming that the locations where the wells are now are the locations of the most productive area. In other words, my point is that there may be and probably are areas that have yet to be drilled up in that field that were very probably as productive as areas that have been drilled. Those areas are between the outer edges of the field and the central axis. I can't spot a particular section in a particular township, but most certainly that

field is not entirely drilled up. I don't think anybody contends that. I probably cannot show you any large area in that field which has not had a gas well drilled on it, but I believe there are many tracts which have not been fully developed by having gas wells placed upon them.

I presume that the area enclosed in the red or purplish line in the west field undoubtedly is the most prolific productive portion of the west field. There is no question about that; but I do not state and I have not stated, to my recollection, that that has been entirely drilled up or that the locations of the gas wells in that west field cover all of the productive area. I think there are some yet that have not been drilled up.

I think I stated in answer to a question that the area of highest productivity was in the region up through the central portion of the area enclosed in red and that the less productive acreage was to the southwest. I think it is true that you find the less productive acreage on the whole down toward the southwest and getting better as you go toward the northwest.

That central area of the west field, that axis along which many of the wells are located, and the area covered
73 generally by the gathering lines of Texoma show substantial reductions in pressure, as indicated by Exhibits 12 and 17, and it is true that in figuring the weighted average pressure of the field, the low pressures in the areas where the greatest productivity originally laid are averaged in with the higher pressures of the relatively less productive areas.

I don't think it makes any difference whether you take the production out of the areas of greatest production in a great field like that in the application of Boyle's law or the pressure decline method of computing reserves, if you have a closed structure with interconnections between practically all parts of that structure. You started out with a given volume and a given pressure, you have certain withdrawals and you experience a certain drop in pressure. That drop in pressure represents the effect of the withdrawals that you are considering. Now, all of these estimates of reserves are necessarily approximate in a certain degree, because in order to have an absolutely scientifically correct estimate it would be necessary to know what the present shut-in simultaneous pressures were in all parts of the reservoir, and that is a physical impossibility with-

out shutting down the field, and it is one you cannot arrive at without shutting down the field.

The point I am making is that the operation of a field of this size naturally precludes the possibility of getting simultaneous pressures and other simultaneous conditions to make a very scientifically correct estimate, so what you do is do the best you can with the most reliable data that you can get. That field is not in equilibrium unless it was shut in and it is true that there is some effect of the withdrawal and the large withdrawals of gas from the reservoir which may have some effect in distorting the picture, but from the best information that you can get, the greatest number of simultaneous or nearly simultaneous readings, is the data that you have to use in considering what is the average pressure.

I know what Boyle's law is. It is a formula of physics that a perfect gas, that is, the volume of a given weight of perfect gas, varies inversely with the absolute pressure. You have got to have absolute pressure. You have got to have absolutely ideal conditions within the container, and you have got to have a perfect gas in order to apply Boyle's law. I considered the deviation from Boyle's law and I considered the effect of temperature, namely, Charles' law. They offset each other in the field to a large extent. The net result is that estimates made according to Boyle's law, with no consideration being given to the deviations from Boyle's law and no consideration being given to the effect of temperature on volumes under the conditions as they exist in this particular field, make the ultimate result a little less than what you would get if you applied those corrections. I later made those adjustments, but the difference was small.

If you had a perfect gas in an air-tight glass container or metallic container that would permit pressure inside and you were to turn a cock at one side of that container, the pressure would equalize immediately within a reason-
74 able area and size. In an area 125 miles long and 35 miles wide at places and at an average of 15 miles in width, the areas of high porosity and areas of low porosity alternating with spots that contain no gas at all in different portions of the field as reflected by Exhibit 17, the equilibrium would not be restored instantaneously even though you shut down all the wells in the field. It would take some time to reach equilibrium pressure.

You assume that, the pressures having gone down in the

areas of greatest original reserve and therefore the areas of greater porosity, gas moves in from those areas of higher pressure or lower productivity to equalize with that pressure over a long period of time, and inquire whether the pressures will be built up higher in the same proportion that they are pulled down at other places. You inquire whether the pressure will be built up in the central or more productive area where the pressure has been depleted at the same rate that it will be pulled down in outlying less productive areas of higher pressures. I don't know just what you mean by the same rate. Let me see if I can answer your question. If you were to shut that field in, then the pressures in the lower pressure areas of the field would be built up by the migration of gas from the higher pressure areas. The rate at which the pressure would be built up would depend upon the rate of migration of the gas—the amount of migration. After a certain length of time, depending on the rate of migration, equilibrium would again be restored throughout the entire field. Those areas that are now portrayed upon Exhibit 17 as being relatively low pressure areas, the ones you have referred to as being along the central axis, the pressures in those areas would be materially increased above what they are as indicated on Exhibit 17.

You inquire whether if the pressures are built up along the central axis or areas of greater productivity by having gas move in from the less productive areas, the rise in pressure along the central axis will be the same in pounds as the drop in pressure in the outlying areas. That question cannot be answered without giving serious consideration to the relative areas involved and the thickness of the reservoir in the two areas.

You assume that the field is shut down and we wait a hundred years and let the pressure equalize. You inquire whether the weighted average pressure will then be 337 pounds. I could not tell you that without making an estimate and knowing the relative areas and thicknesses of producing formations in any portion of the field that you have in mind. In other words, the resultant equilibrium pressure would be determined by the amount of gas that would be moved from the higher to the lower pressure areas, and in order to determine even approximately what that would be from that standpoint, it would be necessary to know first of all how much gas there is in each section of the area involved, how much was there, and the area of

the reservoir voids or the pore spaces over the entire area involved. My estimate of reserves is based on the assumption that if the pressure were equalized it would be 337 pounds, because that is the nearest figure we have to what is the average pressure over the field.

75 You state that there was a great deal more gas to begin with along the central axis than out in those outlying marginal areas where the higher pressures still prevail, and state that the reason there was more gas in there is due to the circumstance that there was more porosity in that area than in the outlying areas, and ask if I agree that that statement is true. It is partially true, but not altogether true. It is not true in the respect that you may have identically the same porosity and you might have a wide variation in thickness. The pore spaces you have under the axis might be substantially different than the pore spaces in an acre out on the edge. There is no doubt that the reservoir void or pore space out where the great volume of gas along the central axis was originally located greatly exceeded that in these outlying areas of relatively small productivity. The reason more gas was there was because there was more room for it—more pore space.

If you take enough gas out of this area which is still above 400 pounds but which is thin in productivity and pull the pressure down 100 pounds and put the gas over in this area, it would build up the pressure in proportion to the pore space or reservoir voids. If the reservoir voids are twice as much per acre in the central portion as they are in the edge, it will not build up as fast or up to such a high point.

Going back to Exhibit 13 and assuming for the purpose of the question that instead of producing the greatest volume of gas along the central axis or to the northeast of the central axis there has been produced the same quantity of gas from the areas to the south and west of the central axis, you inquire whether I would say that the same pressure conditions would exist. My answer is that you would have a reduction in pressure at the point where the gas was produced. I think that if that large production were to have taken place along the south flank of that field rather than along the north flank, you would have something akin to what you have there except in reverse. I think you would have pressure along that

southern flank corresponding to the pressure you now have along the northern flank, namely, below 150 pounds. Whether you would have those pressures sooner than arrived at up where there was a very much larger quantity of gas in place would all depend upon the reservoir space and on the productivity of the area involved. When I said a while ago that if this production had been transferred to the southwest flank instead of the northeast flank that you would have the same pressure conditions that you have now, except in reverse, I meant the low pressure would be on the southwest and the high pressure on the northeast.

(Drawing of two gas cylinders marked Exhibit 19 for identification.)

Exhibit 19 is now exhibited to me. Counsel states that it is a drawing of two cylinders denominated A and B. Below the longer cylinder is written the words "10,000 CF," that is, cubic feet, and under the shorter one is "2,000 Cubic Feet." To each of these cylinders is attached a pressure gauge and between each there is a common outlet to which is attached a valve, called Valve A and Valve B, and these two containers are connected to a common outlet marked G, and there is a meter marked X. Counsel assumes that these two containers are filled with gas, one containing 10,000 cubic feet and the other containing 2,000 cubic feet, and suggests that we see how the operation of Boyle's law to that kind of a situation works out and whether it makes any difference whether you produce your gas from the larger container or the smaller. He assumes the absolute pressure to be 100 pounds in each case, and states that a condition is assumed similar to that which obtained in the Panhandle gas field in the beginning except that 100 pounds is used for the purpose of this illustration instead of 471 pounds absolute in the reservoir. He assumes that we wish to produce from these two containers containing 12,000 cubic feet 3,000 cubic feet of gas and, since there is only 2,000 cubic feet in the smaller container, suggests that the connection be made into the larger container.

76

He suggests that in producing 3,000 cubic feet of gas from the larger container the valve of container B be left closed, and inquires what effect it will have on the pressure of container A if 3000 cubic feet be taken out

of the container having 10,000 cubic feet in it to begin with, at 100 pounds pressure. My answer is that the pressure will be reduced to about 70 pounds. The average of the two, one being 70 and the other 100, would be 85. The proportion of the total gas which has been taken is one-fourth, but the average pressures indicate only 15%. That is on the supposition or assumption that the amount varies directly with the pressure. The fly in the ointment is that counsel did not open both vales and let them equalize.

You assume that equalization had not taken place in the Panhandle at the time I made my computation. That is what I started to say when I was describing the necessity of using the practical data that you have and not waiting for equilibrium in the field. The difference in the problem that you have in Exhibit 19, with two tanks, is that those two tanks, according to your hypotheses and premises, have no interconnection whatever. At no time did you open the valve in B tank. In my opinion, your problem in Exhibit 19 would be synonymous to a condition where you were considering the Monroe field on the one hand and the Texas Panhandle on the other, with no interconnection.

If there were a connection, equilibrium would happen before very long were the containers, say, only 12 inches apart. With an ordinary pipe connection in it, it would take place practically at once. (Objection by Commission Counsel.) If 3000 cubic feet be taken out of cylinder No. 1, reducing its pressure to 70 pounds, and take no part of it out of No. 2, we would have an average in the two of 85 pounds; but that average means nothing because they are not connected at all. If you allow those pressures to equalize, giving them the time that is necessary, they will equalize at 75 pounds, which is a different figure from the 85 at which they started out to equalize.

Counsel states that at a particular time we find pressures in the Panhandle field of 400 pounds, then 380, 360, 340, 320, 300, 280, 260, 240, 220, 200 and on below that. He inquires whether it is not going to take a long time for those pressures to equalize if every well in the Panhandle is shut down. My answer is that I presume it would take quite a while to equalize; but the difference there between that practical situation and this problem is that you do have an interconnection between the two reservoirs. (Objection by Commission Counsel overruled.)

Counsel refers to the Borger field, which is one of the lowest areas designated in Exhibit 17, and suggests that we go across to a point just below the letters H & G N in the northwestern part of Carson County. He says that
77 we find at Borger 200, 180 and 160 pounds and less than that, while up at Obstruction, near the south end of the field, at a point near the letters H & G N, we still have 400 pounds. He inquires whether, although there is interconnection, there has been any equalization there. My answer is that there has been some equalization but probably not much. The process of equalization is going on but it is not completed, as it would be if you opened this valve and let the gas flow over here and equalize those two tubes. I wouldn't say that the yellow high pressure part and Borger were just as far apart at the time the weighted average was arrived at as are these two cylinders with no connections between them. There is a physical connection there but the distance is great and the amount of gas that would pass from one place to the other is evidently small; otherwise the pressures would be more nearly equalized than they are. They would equalize quickly through the tubes if it were not for the resistance offered by the formation.

I don't think it is the case that until equalization takes place you will have the same inaccurate figures when you go to averaging pressures over areas of different productivity in the field that you have when you go to averaging the figures shown on Exhibit 19. I explain the distinction in this way. Take, for example, Exhibit 19 showing the two tanks. I gather that A represents the Borger area of the Texas Panhandle field and Tank B represents a point on the southern flank of the field in northwestern Carson County. You have there definite volumetric quantities representing the most widely separated sections of the field on that cross line. In Exhibit 17, showing the rock pressure map of the Panhandle, we have about 20 bands of pressure areas in between those two widely separated extremes; so that on the one hand counsel has taken an average of the pressures in Tank A and Tank B, which would be an equivalent of taking an arithmetical average of the pressures at Borger and the pressures down in northwestern Carson County. That is not the method, as I understand it, that was used by the Texas Railroad Commission in getting a weighted average pressure of this area. They have these

bands in between, which they planimetered for the various gradients of pressure and then weighted them in.

If we applied Exhibit 19 to Exhibit 16, I presume that Tank A would fall on Exhibit 16 along the east flank of the buried granite mountain where the central axis is, and the area of small production would be over on the south edge of the field. I have said that at the time the weighted average pressure of 337 pounds was obtained they were in a state of partial equilibrium, but not entire equilibrium. It was in the process of equalizing. At that particular moment there was a wide divergence of pressure between the maximum and the minimum, and a gradient from one to the other—not an abrupt change as appears in Exhibit 19.

Counsel assumes that since there are 15 pressure bands, 13 cylinders will be placed in between and that production is taken from cylinder A, which is the one of heaviest productivity. He inquires whether we will get the same average pressure that will obtain when the cocks are all open and we have a state of equilibrium as between the cylinders. My answer is that I don't think so. The comparison is quite different, in my opinion, from the facts, because in determining the average weighted pressure in the field by the methods used by the Texas Commission full weight was given to each of these greatly reduced pressure bands on an acreage basis.

78

In my opinion, the method used by the Texas Railroad Commission in determining an average weighted pressure of the gas in that field is more nearly correct than taking the average from the pressures in the two tanks that you have set forth there in Exhibit 19, for the reason that the method used takes into consideration the gradient of pressure from the high pressure of 400 pounds on the south to the low pressure of 150 and less on the north, and gives effect to a weighing which has been determined, as I understand it, by surveys of the actual observed shut-in pressures in these various bands, and that those bands are determined by contours in the case of the Commission's survey on 50 pound intervals, in the case of your Exhibit 17 on 20 pound intervals.

I believe that those varying pressures and bands and the weighting of them gives an effect of the weighting of pressures and takes into consideration the fact that there is existing at all times an interconnection between these

and an effect of equilibrium or attempting to arrive at equilibrium; but, as I stated earlier in answer to one of your questions, it is of course only a means to an end and cannot be scientifically perfect, undess one did wait until you got equilibrium.

(May 24, 1939.)

Counsel has now caused a tube to be put between the two containers shown on Exhibit 19 and assumes that the tube has an average porosity of 20%. He assumes that the tube opens into each of the tanks; that both are filled with gas and have a pressure of 100 pounds. When the pressure is 100 pounds in the two containers, the intervening space would likewise have the same pressure. In other words, if the pressure in A is 100 pounds and the pressure in B 100 pounds, the pressure in the tube would also be 100 pounds. That was the condition which obtained in the Panhandle when it was first discovered—471 absolute in the formation or 430 well gauge at the top of the ground.

Counsel assumes that a valve is opened on A, and B is closed; that the wells produce 4000 cubic feet from A; and inquires what the pressure will be in container A. My answer is that it would reduce the pressure in container A to 60 pounds if there were no connection between the two; but during the withdrawal and immediately subsequent to the beginning of the withdrawal there would be some migration of gas from B through the interconnection.

If 4000 feet is withdrawn and the pressure is immediately measured it will be found at 60 pounds plus the effect of the gas which goes through the interconnection. It is suggested that one of the containers be put across the street from the other where it would take some time for the pressure to start any movement of gas out of B; but it would start some movement immediately. The quantity of migration would be dependent, of course, upon the resistance through the tube; but if the pressure be taken immediately upon withdrawal it would be ap-
79 proximately 60 pounds, while the pressure in B would be approximately 100. The arithmetical average of the two figures, not giving consideration to a weighting by volume, is 80 pounds. (Objection by Commission Counsel.) There has been an arithmetical average pressure drop as between the two of 20 pounds as a result of taking the 4,000 cubic feet out of container A. That represents

a drop of 200 cubic feet per pound. (Objection by Commission Counsel.) On the basis on which you have presented it, if that is multiplied by the original pressure, you get 20,000 cubic feet as the original reserve of the containers, when as a matter of fact they had only 12,000.

In the meantime there has been some migration between container A and container B. If we wait until 100 feet has been moved out of container B in the direction of container A, 100 feet will obviously have entered container A, and if the pressure is again taken, we will find 95 pounds pressure in container B. Adding 100 cubic feet to container A, which had 6,000 feet before it came over there, would raise its pressure approximately one pound. Then there would be five times the pressure drop in container B as the pressure rise in container A where we have produced the gas.

The arithmetical average pressure between 95 and 61 would be 78 pounds. That represents a pressure drop of 22 pounds. On that basis dividing that into the withdrawal of 4,000 cubic feet and multiplying the result by 100 would give an indication of an original reserve of 18,200, instead of 20,000 as the first indication, and instead of the actual content of 12,000.

In discussing these examples I have used the assumptions made by counsel and the arithmetical averages are on the basis of those assumptions. I am not subscribing to the method.

You state now that we will go on until an additional 200 feet has moved out of B in the direction of A, making a total of 300 feet. That will necessarily mean that 200 additional feet has entered container A. With the total removal of 400 cubic feet from B into A, that would leave 1,700 cubic feet in B and a pressure of 85 pounds, while there would be 6,300 cubic feet in A at a pressure of 63 pounds. The arithmetical average between 63 pounds and 85 pounds would be 74 pounds—a pressure decline of 26 pounds. Dividing that into the withdrawal of 4,000 cubic feet and computing the original reserve therefrom on the basis of the indicated drop of 154 cubic feet per pound, we get 15,400 cubic feet as the original reserve, which is different from the second result of 18,200, and different from the first result of 20,000, and still different from the actual original reserve of 12,000 on that basis. On the basis of arithmetical averages, no matter where the

pressure is taken before equilibrium is restored, you will get a distorted result indicating more gas than was actually there.

If you go down until 666⅔ cubic feet has moved out of container B over to container A, there would be left in container B 1333⅓ cubic feet and the pressure would be 66⅔ pounds. In the meantime 666⅔ cubic feet have entered container A, from which the 4,000 cubic feet had been withdrawn, and this would have raised that container to 6666⅔ cubic feet, and the resulting pressure 66⅔. They have equalized then. The pressure for B is 66⅔ and
80 the pressure for A is 66⅔, and that is the average for each of them. The pressure loss has been 33⅓ pounds average loss between the two. If the 4,000 is divided by 33⅓, the result is 120. Multiply that by 100 and the result is 12,000, the exact amount which we started out with; so when equilibrium has been established, applying the method as it has been applied, whether right or wrong, we get the original volume.

I would like to give you my idea of the difference between the application as made by me in estimating the reserves in the Panhandle field and the problem you have set forth, and the manner you have set it forth in Exhibit 19. When we get to any pressure that is equivalent—that is, the same pressure in both your containers, whether it be the initial pressure of 100 pounds or whether it be the final pressure of 66⅔—at those two points, call them end points if you like, they represent both the weighted average and the arithmetical average.

You suggest that you might meet the objection I have made by assuming that the top capacity of container A, the acreage in container A, is just twice as much as it is, and leave B shown as it is. By having container A double its width so that there would still be 10,000 cubic feet but twice the surface area—twice as much contour as we started with, it would meet my objection if you weighted the various factors in this in accordance with volume.

What the Railroad Commission did was to weight the average of pressures in the field on an acreage basis. You ask whether the Railroad Commission paid any attention to content or only considered pressure and acreage in determining their averages. As far as they went, it was to determine on an acreage basis the weighted average

pressure of the field without regard to where the gas was in its distribution over the field. In my estimate I included the factor of thickness of pay, which in fact took into consideration volume. You state that I didn't say anything about sand thickness or pay thickness or volume in my pressure decline computation. I must of necessity assume a certain thickness. I assumed that every acre in the field had as much gas under it as any other acre. I assumed an average thickness over the field. I know it would not be constant in the Panhandle, but there most certainly is an average, just the same as we had an average by taking these two dissimilar containers. There is always an arithmetical average.

You next state that you are going to weight it on the basis of acreage by making container A twice as big along the top as container B, but it has the same quantity of gas in it; that there is twice as much acreage in A but still the same quantity of gas, and that B has the same quantity of gas. You refer to Exhibit 13 in this connection, where the production is around five million and below but which has 430,000 acres of land, and comment that there is about twice as much acreage where the production is better and the original reserves were higher—about 2½ times as much in productivity. You suggest that we make the area twice as big and withdraw 4,000 cubic feet as was done in the other problems. The pressure would be 60 pounds, but it will be 60 pounds over twice as big an area.

If I remember problem No. 1, it involved the with-
81 drawal of 4,000 cubic feet out of cylinder A with an immediate, or very close to an immediate, reduction in pressure from 100 pounds to 60 pounds and then the determination of the arithmetical average between 60 pounds and 100 pounds, or 80 pounds. It is now 60 pounds in A, over an area which is twice as large as it was before. You ask me to weight the average pressure produced in A with that of B, and then solve the same problem indicating the original reserve.

Now, on an arithmetical average basis we arrive at the figure of 80 pounds. In weighting it on the basis of the area in the top of the cylinders, which you say would be an acreage basis, the top of cylinder A being twice the area of the top of cylinder B, we would have a pressure in

cylinder A, which is 60 pounds, being given twice the weight of the pressure in cylinder B, which is 100 pounds, so that we would have a figure of 120 pounds weighted average for A and 100 pounds for B, the sum of which would be 220 pounds, which, divided by three, would be 73⅓. The pressure drop was 26⅔. Dividing that into the withdrawal of 4000 cubic feet, we get 149.5, and multiplying that by the original pressure we get an indicated original reserve of 14,950.

When we weight the average on the acreage basis we still get 25% more gas than was originally there on this particular set up and basis where you have twice the area in the one as in the other. You inquire if having an area 2½ times as great there would still be a distorted picture, as in the case of the Panhandle field; but I state that the situation is different. The nearer you come in any problem of this sort to weighting your pressure on the basis of total volume, the nearer you come to accuracy.

You state that the Railroad Commission paid no attention to volume but weighted it according to pressure and acreage. They did; but they did not take the two ultimate extremes. The other determination was isobar contours and gradient of pressure; and theoretically the closer those contours are calculated and the greater number of those isobar contours, the truer becomes the gradient of pressure, so the more nearly correct you get an answer as to the average pressure over the area. The difference between what was done by the Texas Railroad Commission in their determination of average pressures over the field and the problem that you have set forth here with your Exhibit 19 is that you have used terminal pressures and terminal conditions and taken an average directly and arithmetically between those two; and they, in their determination of the average pressure, have used these bands, or, in other words, they took into consideration the pressure gradient.

You suggest that we move these cylinders and put one over in the area in the middle of the north part of Potter County and the other one in the middle of the south part of Moore County, and calculate from band to band, where we won't cross any intermediate bands at all, and ask what would be wrong with the application of the principle which has been demonstrated. The principal thing is that you have used an arithmetical average instead

of a weighted average and personally weighted it on
82 the basis of the change in area of the top of the tube.
(Objection by Commission counsel.)

You next suggest that the Texas Railroad Commission, in arriving at its so-called weighted average of 337.66 pounds per square inch, disregarded everything except pressure and area. They based it principally upon area—perhaps entirely on area and pressure. (Objection by Commission counsel.) I want to say that they did determine, as near as I can interpret from their report and methods, what in their minds was an average pressure over that entire field by the determination of certain pressure contours and isobars and then giving each pressure band a weight in the amount of pressure included in each pressure band. So that they got the pressure by determining weighted pressure bands covering the entire area, and the number of those bands, each band having its weight, that is true—that would be a weight in accordance with the area in which they found certain pressure brackets.

Questions by the Examiner.

The Examiner inquires whether the Commission has any subsidiary breakdown of that map which they used in their calculations. On page 12 of their report, marked IV, "Pressure analysis of the Panhandle area, July, 1938," they set forth the pressure classification of those brackets at the left hand side. Then they show successively the West field, the East field, the South field, and beneath that the total Panhandle field. They have brackets from zero to 150, 150 to 200, and so on up to 400 and over, and the total of wells in each case, and in each field, a total of acres in each field, and each bracket, and apparently a total potential production. Those potentials of production are open flows. They are based on tests of the wells.

The Examiner inquires whether this number of wells works into the calculation at all or any part of the weighting. They state here the total number of wells in each pressure bracket, the percentage of the total, the MCF potential, and percentage of the total; and the acres in the bands, and the percentage of the total. I doubt whether anywhere in this report the Commission states what its weighting process was; but I do note that these potential open flows and the number of wells and areas are here. I stated in answer to one of Mr. Morgan's questions that it

was my thought that the Commission determined its weighted average pressure upon area and pressure, but I note these wells and potentials which may be weighted in on this thing, which may reflect volume. That may be a factor which would enter into my answers on further cross-examination.

Cross-Examination Resumed by Mr. Morgan.

You ask if the Commission, in arriving at the so-called weighted average rock pressure of 337.66, did not go into the area colored yellow on Exhibit 12 and examine the pressures of all the wells in the yellow band. I think inasmuch as Mr. Cottingham, who made up this report, is here, the best evidence should come from him as to what the Railroad Commission did. He is better informed as to what they did than I would be.

I have examined that report and satisfied myself enough about the 337 that I am willing to come here and testify
83 to that vital issue in this case and use 337.66 as the weighted average pressure of the field. There is no evidence in the report that the Commission took the pressure of every well in the yellow area and arrived at the arithmetical average by adding up the pressure and dividing by the number of wells. As to whether there is any evidence that they considered anything except acreage, they set forth in there, potentials and the number of wells, and they come out with an answer which purports to be and which is stated to be the weighted average pressure of the whole field. There is nothing in the report that indicates the calculations that were followed.

You ask me to explain how they could use potentials in arriving at the weighted average pressure, and what potentials have to do with pressure when we are talking about the weighted average pressure. The potentials are the estimated amounts of flow, or rate of flow, of the wells and have something to do with the volume of the wells. Ordinarily speaking, the potential of a well is the amount that that well is capable of producing, ascertained either by calculation or test.

Down in Texas they have what they call proration production among the producers in all of the oil fields in that state, and in prorating the production, or allocating the production among the different producers, they are required under the regulations to give effect to the potential

producing capacity of the wells. As to whether that is the reason they are talking about potentials on the same page that they are talking about the weighted average pressure, that I think the best evidence as to that is the person who prepared that page. I think Mr. Cottingham can furnish the best evidence in connection with that.

You inquire what I assumed the weighted average included when I adopted the figure and made it the basis of my computation. I assumed that the weighted average was as it is set forth on that page, namely, 337.66. I assumed that it was the best estimate the Commission could make of the weighted average pressure of that field. I made no assumption at all as to whether it was based on pressures and acreage alone. I took their figures as they reported, that is, 337.66. When you asked me this morning if that is not what they did, I thought at that time it was. When I adopted the figure, I accepted it as their best judgment of the weighted average pressure in that field, and at the time I adopted it I thought that figure was a result arrived at by considering acreage and pressure alone.

The way of doing that would have been to go to the yellow bands or yellow patches and count the number of wells there and take the pressure of each well and divide the sum of the pressures by the number of wells and thus arrive at the average pressure of the wells in the yellow areas, and then multiply that by the number of acres in the yellow patches, and you would get a product. Leaving the yellow band and going over into the green, you would count the number of wells in the green area and observe the pressures of each one of them, and then you would divide the sum of the pressures by the number of wells to get the average pressure of the wells, but it would not give you the average pressure per acre.

We would do the same thing in all the seven bands,
84 and then add all the products and get a total. In order to get the weighted average pressure of the field we would divide that total by the total acreage.

When you take all of the wells, test them for pressure, add the aggregate pressures together and divide by the number of wells you get a result that is weighted by the number of wells. The thing that the Commission did in multiplying the number of acres in the yellow patches by the average pressure of all the wells was the element of weighing that got into their calculation, if that is what they did. If we assume that is what they did, and they added

all these totals up and got a total and divided it by the whole number of acres, this is the kind of weighting they did, on the assumption on which we are proceeding here. The way you set it forth it would be a weighting as to pressure bands or on an area basis.

In order to apply that sort of a weighted average—a weighted average based on area and pressure alone—in estimating reserves of gas in a reservoir, you do not necessarily have to assume that every acre in the field has exactly the same content of gas as every other acre in the field, or had in the beginning.

Coming back to Exhibit 19 and to the two original cylinders of the same size at the top, and extending container B down to where it will also contain 10,000 cubic feet in the beginning, let us draw 4000 cubic feet of gas from container A as we did in the beginning. The arithmetical average pressure of the two containers would represent a pressure drop of 40 pounds in A and nothing in B, or an arithmetical average drop of 20 pounds. The arithmetical average between 60 pounds remaining in A and 100 pounds remaining in B would be 80 pounds. This represents a withdrawal of 200 cubic feet per pound drop, and multiplying that by 100 we would get 20,000 as the original content. We are starting out with two identical cylinders representing the same size areas and having the same content per unit of area. In applying that formula, every acre having exactly the same content as every other acre, you get the right results because those are weighted for volume when you start out and end up in the same identical cylinders. If you assume that every acre in the Panhandle has just as much gas under it as every other acre in the Panhandle, you can apply that formula and know you will get the right result, regardless of what the weighted average is.

Of course, in the Panhandle you do not have the situation of having the exact amount of gas under each acre that there is under each other acre. It would be a very great coincidence if that were true; but there is an average amount of gas under each acre. There is an average between 2,000 and 10,000, and if we weighted it according to area, as we did when we doubled the area of container A, and considered nothing but area, we still get the wrong result, although we arrive at the proper averages; but we get the right result if we weight it as to volume. I am waiting to hear what the Railroad Commission did in that respect. If we assume that they did not—if they considered

nothing but acres and gave no effect to volume as distributed out through the field, then when I adopted their weighted average and made my calculations on that basis I did not get the right result.

85 You ask us to suppose that, instead of producing that 4000 cubic feet out of cylinder A, we produce it from both of them in such a manner and at such a rate as that the pressures would go down in each cylinder at the same rate, and that if we produce this 4000 cubic feet from these two cylinders we would have to produce 3333⅓ cubic feet from A and 666⅔ cubic feet from B, if we wish to have our pressures go down together instead of having the weight equalized through the tube. Then the pressure in container A and container B would be exactly the same, and, working the problem, it would come out 12,000 cubic feet. That would be the same rate of withdrawal based on weighting by volume of each cylinder.

If there had been a well drilled on every 640 acres in the Panhandle and enough gas withdrawn from each of those wells so that the pressures would have come down together, you could apply my formula in computing estimates and get the right answer. I think it approximates it the way it was done, the greater portion of the production coming from the most prolific area.

You ask me to take a look at Exhibit 17 and tell whether that is what has been done in the Panhandle and whether that is true as reflected by that pressure map. My answer is that, of course, that pressure map indicates that there has been by far the greater amount of production in the most prolific area and to the northeast, and that the effect of those withdrawals, as they have been made, has resulted in a lowering of the pressures in the central or axial area and in the northeast area to a greater extent than in other parts of the field on a pound basis; that is true. You certainly have not uniform pressures throughout the field; that is obvious. It does not necessarily follow that the same content per acre does not prevail throughout the field. I did not state that I think every acre in the field has the same quantity of gas under it as every other acre in the field. I think it is perfectly reasonable to assume that each acre within that reservoir does not contain the same quantity of gas as every other acre in the field. I would say that it would be an extreme coincidence if there were identically the same quantity of gas under any acre in the field.

That is true of the Panhandle as in other fields. It is characteristic of gas fields.

You ask me the reason for fencing off about 1,033,000 acres inside a reddish line on Exhibit 13 from the rest of the field, which you state I admitted yesterday was much leaner and less productive of gas than that which was included within the reddish lines. My answer to that is for the simple reason that the characteristics of this field, in the same manner as in other fields that are formed by synclines or domes, are that the area that is productive is included in the top of the dome or the top of the syncline and pinches out toward the edges of the productive area. In this particular field, on Exhibit 13, the productive area or potentially productive area is delineated by the black line which forms the outside boundary of the field. Now, if that is the boundary and the limits of production, obviously as you approach closely to that outer boundary from any point inside, it could be assumed that the area is approaching the non-productive state, and, therefore, it is very
86 probable that the most productive or, as your Mr. Peterson stated, the best commercial area of the field is somewhere on the inside.

There is a variation in this field in both porosity and permeability of the structure that produces gas; that may have something to do with it. We find, for example, in eastern Gray County areas of relatively small productivity running clear across the field.

I agree with your suggestion that if you assume the same content under a given area as obtains in every other area of the same size throughout the field, the formula will work, regardless of whether the pressure is equalized or not.

(Objection by Commission counsel to form of question on hypothetical basis with ruling first reserved and then overruled.)

(At this point the following questions and answers appear:)

By Mr. Morgan:

Q. (All right. Let us pursue this same method of computing that you have used and assume—and this is hypothetical and not tentative—we will assume that it turns out that this field does not stop where this black line is at all, but that it is just twice as big as it is and that there is an extension off down here to the south containing 1,475,000 acres. Let us assume for the purpose of the hypothetical

question that I am going to ask you that that vast area of 1,475,000 has an average of 1,000,000 cubic feet per acre under it. It is over here where the production has not pulled the pressure down. It is over here adjacent to this area colored yellow and the band of green on Exhibit No. 12, and it has not been producing. There are 1,475,000 acres all in this field directly connected with the rest of the field, the pressures of which have not been disturbed at all, but it is lean, it has a million cubic feet per acre. Now, I want you to apply your formula to that situation and see how you come out.)

A. "You want to me estimate—"

Q. (I want you to apply your formula to that situation and tell what the indicated reserve based on the same weighted average pressure that we have been talking about would be. I want you to weight this acreage in.)

* * * * * *

(Objection by Commission counsel noted.)

(Mr. Morgan: All I am doing is to point out the fallacy of his formula by extending this yellow patch so as to make it include another area, assumed area, the exact acreage of the area being the area I selected up here in order to make it easier to figure. I could have said or supposed the extension to come down here (pointing on map) and bring in another hundred thousand, but it would not be so easy to figure. What I want to bring out is that when he applies his formula to this area, which has not been hurt by production, over here on the northeast flank, the present area, that the result is wholly out of line with what the assumed facts are.)

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(Mr. Morgan: Here is my position, Mr. Examiner: I am merely trying to get this witness to use an illustration that I have advanced here. He has said that the weighted average here of 337 pounds, which he assumed at the time he adopted it, gave no effect to anything except area and pressure, and no effect, so far as weighting was concerned, except to area, and that he has gotten the right result, and he still stands pat on that, in a question I asked him just a moment ago. Now, I want to show how this formula would apply to a situation such as I have described here where there is a connected area extending this field down here (indicating on map) so as to include another 1,475,000 acres with the original pressure of 430 pounds, but containing only 1,000,000 cubic feet of gas per acre. I want to

show just what highly distorted result is reached by applying the same formula he has used here and weighting in that 1,475,000 acres along with the other acreage already weighted in.)

* * * * * *

(Examiner Simpson: Give me those field figures again.)

(Mr. Morgan: You see this field contained within the colored area which is productive of gas, 1,475,000 acres.)

(Examiner Simpson: Yes.)

(Mr. Morgan: Approximately. Now, in order to double the acreage I just assumed an extension down here on the south where the pressures are still high of another area containing exactly the same number of acres.)

(Examiner Simpson: Yes.)

(Mr. Morgan: That would be an additional 1,475,000 acres, and for the purpose of showing that his formula will not work, I am assuming that in that extension that it contains only 1,000,000 cubic feet per acre, leaving the other part of the field exactly what it has now, with the same pressure it has now, so that instead of having to weight into the picture, the patches that are colored in yellow on Exhibit No. 12, I weight in those patches plus the 1,475,000 acres. I have only added the 1,475,000 acres to the total reserve, said acres containing one million cubic feet of gas an acre or a total of 1,475,000,000,000 cubic feet.)

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(By Mr. Morgan:)

Q. (Mr. Brown, I want to direct some questions that are based on the following assumptions: Over here in the area which is still yellow and where the pressure is still indicated to be about 400 pounds, substantially its original pressure, on Exhibit No. 12, we assume an extension of this field in a westerly and southerly direction, extending over to where this area of high pressure plays out, and containing 1,475,324 acres, just exactly the number of acres which the records shows are contained in this field, here and assume that that pressure is still 430 pounds as it was in the beginning, and assume that it has a content of natural gas of one million cubic feet per acre. Now, I want you by the same method which we have assumed was used by the Railroad Commission, to weight in that additional acreage and give me the result of that weighting in from the standpoint of indicated reserves contained within the whole great reservoir containing all that is here and what would be

added to it by the extension of the field. Do you understand my question?)

A. "I understand your question, but it will be necessary to know what the Railroad Commission of Texas would consider under those conditions as the average pressure of that field."

Q. (That is what I want you to find out for me.)

A. "I am waiting to hear how they did it."

Q. (I want you to assume they got it just exactly like it was stated here this morning, for the purpose of this question, and I will connect this up. I want to use the same yellow patches, covering 1,475,324 acres, assuming their weighted average for the present field, but add the assumed extension of 1,475,324 acres with the original pressure and weight that acreage in at the same pressure, and bring that back to the hearing I should say immediately after recess. It is going to take a little while to do this. Bring in the result of that computation.)

* * * * * * *

(The Witness:) "I would like to state this: It will be necessary to know what method was used by the Commission and what weights were given to that by the Commission in their pressure readings in arriving at 337.66 as an average pressure. What Mr. Morgan is actually asking me to do is to assume there is an area additional and immediately adjacent to this field which has in it one million cubic feet per acre, and in which the pressure is 400 pounds or better at the wellhead of any wells in that area. Further, that there has been apparently, as I understand it, no withdrawal from that area."

(Mr. Morgan: Correct.)

(The Witness:) "And it has its virgin pressure."

(Mr. Morgan: 430.)

(The Witness:) "430 pounds, and it is entirely a virgin area added to this particular field. Now, he is asking me to weight that in in the manner that the Railroad Commission of Texas would do if that area were included in this field, and I submit that it will be essential for me to know how they arrived at their figure and what methods they used in order to give this the proper weight and in order give the weight for this field."

(Examiner Simpson: Judge Morgan, would it be possible to employ that example with your own witness; would you get the same result?)

(Mr. Morgan: I can do that with my own witness, but I

was trying to shorten the matter, because I am doing my best to show the Examiner that the formula that he used, which is an appalication of Boyle's law, cannot be used in the Panhandle of Texas with the conditions that obtain in the reservoir without getting a grossly distorted result, and this is simply an illustration of it. All he has to do, and there isn't any trouble about it—it is perfectly simple, a perfectly simple problem that I had worked out in 30 minutes, in which instead of having this area here with the average pressure of the wells, as the Railroad Commission found them to be and weighted them in at some figure above 400, we do not know what, all I ask is that he weights in another band of 1,475,324 acres of virgin pressure at 430 pounds.)

* * * * * *

(The Witness:) "May I make a statement?"

(Examiner Simpson: You may.)

(The Witness:) "What Judge Morgan is asking me to do is to change the conditions hypothetically in that field and calculate an average, weighted average pressure for the field different than was arrived at by the Railroad Commission of Texas."

(Examiner Simpson: Mr. Brown, suppose we take this whole matter under advisement and you consult with anyone you deem it necessary to consult with to get the question clearly.)

(The Witness:) "I submit this: As I stated in connection with my direct testimony and in answer on cross-examination, that for the purpose of using one method, which I used to determine the original reserves in this field, I accepted a figure in a published report by the Railroad Commission of Texas which is stated and purports to be the weighted average pressure of this field in question. Now, counsel for defendant is asking me to assume conditions that are entirely different than exist in this field, and to use the same method as used by the Railroad Commission when they determined their published average weighted pressure of 337.66. Now, my point is this: I am perfectly willing to do anything that should be done; I am glad to accommodate Mr. Morgan, but I first must know the method used by the Railroad Commission in determining the figure that they published before I can arrive at another figure under hypothetically different conditions, and I submit that the best evidence as to the method that

they used should be given by the man that used it in his report."

(Examiner Simpson: Judge Morgan, can you tell the witness the method they used?)

(Mr. Morgan: I have no objection to telling him. I was just going to suggest that I would be glad to tell the method, and I will connect it up later on. The method they used, Mr. Brown, is the method used when we were considering Exhibit 12 earlier in the day. They counted the wells in every one of those areas and they took the pressure of each one of those wells, divided the sum of those pressures by the number of wells and got at the arithmetical average of the wells in each band separately. They then multiplied the average for each band by the number of acres in that band and added the seven products together and divided by the total number of acres in the field and called that the weighted average of the field.)

(Examiner Simpson: Mr. Brown, whether the Commission used that formula or not, is that a formula you can use in getting some kind of a result?)

(The Witness:) "I do not think that counsel is interested in me getting some kind of a result. I think he wants me to arrive at a result that is comparable to the result secured by the Texas Railroad Commission when they got that figure of 337.66."

(Mr. Morgan: No, that is not my point at all, Mr. Examiner. I am simply testing his own formula. He has come in here with a formula by which he undertakes vitally to affect the rights of a great concern here that has money invested in a property extending all the way from the Panhandle of Texas to Chicago. I am simply asking the privilege of testing by asking him to add another band with 430 pounds of pressure to that area and to apply his formula to that and see what it will indicate. That is all I am asking him to do.)

* * * * * *

(Mr. Morgan: I am asking him to assume an extension of that field containing another area exactly the same size at the virgin pressure of 430. Now, you add 337 and 430 and divide them by two, and you have got the weighted average of the whole area. That is how complicated it is.)

* * * * * *

(By Mr. Morgan:)

Q. (I have asked the witness to assume an extension of this field pictured on Exhibit No. 12, at the high pressure

southwest portion of the field, so as to add to it another band or zone, such as these seven that are pictured in the colored portion of the map, except to assume that it has the same area as the entire field. The only reason I picked out that particular area was to simplify the problem that I wanted to submit to the witness as a test of his formula. I asked him to assume also that that area had pressure comparable to that of the outside of this yellow area here, which we know is somewhere between 400 and 430, by the legend of the exhibit.)

(I have asked him to assume also that that was a lean area for the purpose of testing his formula, and for that purpose only, that is, an area of small productivity, and that its pressure is still above 400 pounds, somewhat above, perhaps, but approximately 430, its original pressure; and then to weight the pressure and average of that area into the pressure and acreage of the area which he has used as the basis of his formula here, and to then apply the same method that he used in his own computations to the enlarged area, with the eight bands, applying it across eight bands instead of seven, on the theory that if it is good across seven it ought to be good across eight. That is the problem, and I wanted to see what would be the indicated reserves in the enlarged field.)

* * * * * *

(By Mr. Morgan:)

Q. (I won't assume any content at all, Mr. Brown. Now can you give us the indicated content?)

A. "I can figure it out, but first, in order to figure it out, I may state that any additional acreage or extension in this field, such as you have assumed, will constitute an additional source of gas by migration to those portions of the field wherein the pressure has been substantially lowered due to large withdrawals and, the addition of this field of the magnitude that you have assumed, might well change the location of the bands, as shown in both Exhibit No. 12 and Exhibit No. 17."

(Examiner Simpson: I think that is a fair comment.)

(By the Witness:)

A. (Continuing.) "Therefore, if it is true, as you say, that the weighted average pressure of this field is 337.66, as determined by the Texas Commission and as used by me in my calculation of the content of this field in one method that I use, then it would be necessary, if those bands are changed in area or location, to determine that fact, in order

to arrive at a new weighted average pressure of the entire area that you assume."

(By Mr. Morgan:)

Q. (All right. Now, let us go over here to your Exhibit No. 12. What is it that causes the pressure in this green area here, which runs almost the full length of the field, immediately outside of the blue and inside of the yellow,—what is it that causes that pressure situation to obtain?)

A. "The withdrawals of substantial quantities of gas from the field."

Q. (From what part of the field?)

A. "From the northeast flank."

Q. (The northeast flank of the field?)

A. "Yes."

Q. (In other words, by reason of a pressure differential between the northeast flank of the field, where the pressures were pulled down very rapidly in the early history of the field, we have had a migration of gas to the northeastward from the field as a whole?)

A. "That is right."

Q. (It has affected the pressures out across that field, except to the yellow area, to the extent that they have now been pulled down below 400 pounds?)

A. "Why do you except the yellow area? I don't understand your hypothesis."

Q. (I say to the extent, except to the yellow area, that they have pulled down to where they are now below 400 pounds.)

A. "I see."

Q. (That is correct, is it not?)

A. "Yes."

Q. (And in the yellow area they have been pulled down some also?)

A. "That is correct."

Q. (By the same influences?)

A. "Yes."

Q. (But they have not been pulled down to 400 yet?)

A. "That is right."

Q. (They are still above 400, somewhere between 400 and 430—the exhibit does not disclose just what the figure is—that was reached by taking the pressure of all of the wells in that area and arriving at their average?)

A. "That is right."

Q. (Now, what influence on these bands could it have if there was still a large area out here that had not been

reached by the influence of this low pressure area, which has not been sufficient to get out to the edge of the field as yet?)

(Examiner Simpson: Where is "here" Judge?)

(Mr. Morgan: In the southwest corner, southwestern portion of the field.)

(By Mr. Morgan:)

Q. (Those pressure differentials resulting from the heavy production of gas along the northeast flank have not yet been sufficiently influential on the pressure near the southwest projection of the field and the southwest flank of the field over to a point well within Carson County, to the extent that the pressures have been pulled down as much as 30 pounds, as yet; that is true, is it not?)

A. "It is true that those areas marked yellow have been affected less, as far as pressure is concerned, than the other intervening bands. Now, they have been affected some."

Q. (Correct. But, now, why would the assumption of an area out here beyond the yellow and the assumption that it had not been affected substantially by this production over on the northeast flank in any sense change the location of these bands that have been located by the actual pressure tests that have been made out there in the field?)

A. "It is simply this, that in my opinion it would be impossible, if an area existed adjacent to and connected with this field in the location that you indicate, for some gas not to have migrated from that additional extension, if you please, into the present yellow area, and thence on into the area of greatest drainage or greatest withdrawal."

Q. (You could not say how much, of course?)

A. "I would not attempt to."

Q. (I would not expect you to.)

A. "No."

Q. (Let us then assume that that pressure had been pulled down to the same pressure as this yellow area and just treat it as an extension of this yellow area which we have here now.)

A. "All right, when we do that we introduce an error right away, because you are assuming a substantial area here as an extension of the present given area. And let me say this; that whatever the amount of gas is that has been withdrawn from the actual yellow area as it exists, it has had its effect in the determination of the location of the isobar lines which form the border of these bands, and if there had been three or four times the area in that yellow

area that there is actually, a difference in the amount of withdrawal and migration of that gas would most certainly have had its effect upon the pressures in the field as a whole."

"Now, the reason that the green area extends as far west as it does is due to the limitation of the amount of gas that has migrated from that yellow area. If, let us say, twice the gas—"

(Mr. Morgan: If the Examiner please, in view of the manifest reluctance of the witness to answer the question, I withdraw it. I will bring in my own witnesses to prove it. He is telling about a matter I did not call for at all, and I just withdraw the question, in order to stop his speech.)

(By Mr. Morgan:)

Q. (This morning, we were talking about the effect of applying the pressure decline method of computing reserves to a situation where we had exactly the same content of gas under every acre of the field, and it was developed that if you assume the same content under a given area as obtains in every other area of the same size throughout the field, that the formula will work regardless of whether the pressure is equalized as yet or not. It also works out that if you so produce from the field as a whole so that your pressures come down uniformly, and any time you take the pressure you will find the pressure of every well in the field just the same as the pressure of every other well in the field, you have got your weighted average there when you go in to test those wells. They are the same all over, and there is no difference in the pressure in the various parts of the field.)

You can take the withdrawal per pound drop and use the formula referred to and, calculating back, arrive at the correct result under those conditions.

You inquire where you do not have those conditions, as is the case in the Panhandle where the pressures vary greatly and where the productivity is highly variable, if that formula can be applied to the whole situation by taking the weighted average of the field, weighting in the pressure and the acreage or area only, with no consideration given to content per unit of area. My answer is that you can by that method secure an approximately result, that is, an approximation as to the amount of gas in that area. As I stated this morning, I believe under cross-examination, this method of determining isobar pressure bands, contours, and weighting the pressure within those bands on the basis

of area, is probably the nearest approximation that one can arrive at.

(The Witness:) "You ask if when I use the figures that I used in my assumption, if it be true, as we have assumed it is for the purpose of my cross-examination, that they did not weigh in the content per unit of acreage but that they weighted in the average, some of which was highly productive and some of which was comparatively non-productive, I get a distorted and erroneous answer if I apply that formula. The volumetric content is the thing that we are trying to find by the application of that formula. Now if you had the volumetric content of the reservoir prior to the application of that formula, there would be no necessity to apply the formula. My point is this: What we are trying to get when we make an estimate of the natural gas in the field is the volumetric content."

(Witness interrupted by Company counsel because answer was not responsive. Question withdrawn and restated.)

You ask if I can apply the pressure decline method of computing reserves in a great area like the Panhandle, 124 miles long and an average of 15 or 20 miles wide, where the conditions are as this record shows them to be in the Panhandle with which I am now somewhat familiar, with the formula based on weighted average pressures, which are weighted as to area and pressures only, without regard to the content. My answer is that I can do that and that is what I have done.

(Objection by Commission counsel.)

87 You ask whether if I took the field by small areas and applied my principle to those small areas, where I have greater knowledge of local conditions as to pressure and productivity and things of that sort, I might arrive at a more accurate result in that particular local area than I would over the whole field. I doubt if that is true, because any area that we would pick out of the field would be a part of the whole, and there would undoubtedly be factors of the pressure drop in that particular area by migration of the gas elsewhere. The trouble would be the migration, and you couldn't tell how much had been produced down to the weighted average pressures as taken in that small area. That is the principal difference between treating a small local area and the whole structure.

If I knew the withdrawal from a local area, I don't think I could arrive at the original reserve of that area by ap-

plying the pressure decline method in that local area. If it was surrounded so that the migration factor was eliminated, either out or in, then you might determine your original pressure and withdrawals and the reduction due to those withdrawals. Then I could do it.

Under the operation of Boyle's law, where pressure declines directly with the volume of gas under pressure, in confinement, the same withdrawal in terms of gas ought to result in exactly the same pressure drop, regardless of whether it was done early in the process of exhausting the gas out of the container or later on, assuming that no gas goes in or goes out during the withdrawals that you use.

Going back to Exhibit 19 and taking container A and assuming that it has 10,000 cubic feet of gas and we withdraw 1000 cubic feet from that container, the pressure will go down to 90 immediately. If we average it with B we get an arithmetical average of 95. Now, considering just container A and assuming no connection between A and B, and starting out with 10,000 cubic feet and withdrawing 1000, we have a remaining pressure in A of 90 pounds. If we withdraw another 1000 it would leave a pressure of 80 pounds, a ten pound drop. I assume the withdrawals are on the same pressure basis. If we take out half the volume we will have left half the pressure. In taking out the first 1000 feet we get a drop of 10 pounds, or one pound per hundred of withdrawal, no matter at what stage of the proceeding you do that. That is strictly in accordance with Boyle's law.

I have not studied the pressure drops from year to year during the past several years in the Texas Panhandle to ascertain whether or not there has been a uniform per pound drop in proportion to withdrawals from year to year. I don't know that it would be a very simple way to check my formula. It would be a simple way, assuming that conditions were identical throughout that whole period of time; but I didn't do it.

I presume that the Railroad Commission's report for 1937 has a weighted average just like it does for 1938. I can figure out the production from July, 1937, to July,
88 1938. Those figures were available to me just like the others were. I think I could have gotten the withdrawals from 1936 to 1937 by the same means and from the same source that I obtained the figures which I used. I presume that the weighted average pressures in 1936 and 1937 are in the Railroad Commission's report; but I didn't

see them. Assuming that they are in the reports for 1937, 1936 and 1935, and I could get from the same source I got my other information the withdrawals from 1935 to 1936, 1936 to 1937, and 1937 to 1938, it would be a very simple matter to see whether or not there has been the same per pound loss based on each unit of production from year to year during those four years by following through the process used in 1938, and when that is done I would say that there should be an approximately comparable per pound loss per billion feet of withdrawals, same withdrawal of production per pound drop from year to year. There are probably some factors that would enter in which would make them not comparable; but I should say that they should be pretty close.

I don't know whether if there is any wide variance in that pressure, that would be something that would indicate there was something wrong with the formula. I would have to make the computations and check the conditions there during each of those years to see if there were any substantial differences and changes which occurred in the field.

I used the 1938 information and data when I brought in my figure of 23 trillion cubic feet. The same information and data could be used for 1937 and for the interval between 1937 and 1938 and for the interval between 1936 and 1937 and the interval between 1935 and 1936. I think it would be a way of checking what I have shown here to see whether or not the pressure drop has been uniform on the basis of withdrawals during that period of four years, granting that the data is available.

I computed these reserves by another means which I described as the reservoir-porosity method. By that method I proceeded as follows: using the area in an acre of 43,560 square feet, multiplying that by an average assumed thickness of pay of 70 feet, and also having a porosity of 20%, I arrived at a figure of reservoir pore space per acre of 609,840 cubic feet. By that I mean that there is one-fifth in total volume of pore space in these porous substances, of the total volume of this porous substance. Then using the initial wellhead pressure of 430 pounds, which corresponds to an initial reservoir pressure of 471 pounds absolute, and changing that over to a pressure base of 16.4 pounds absolute, I arrive at a figure for the initial gas in place per acre in the reserve of 17,514 MCF.

After determining 17,514 MCF per acre as the total gas

in place on a pressure base of 16.4 absolute, I used the fraction 431/471 of that to determine the amount of gas available for production reduced to a wellhead pressure of 25 pounds gauge, which was 16,027 MCF per acre.

I have known of 20% porosity being used before in estimates of reserves in this area. I also discussed the question of porosity with Mr. Peterson, the geologist of the Texoma Company, and I understood that he agreed with that figure and used it. I don't remember that I dis-
89 cussed it with anyone else. I had seen the figure used and had seen results of estimates made with that figure. I never made a study or determination of the porosity of that formation down there. I looked at samples of the formation, and discussed it with Mr. Peterson, and found that he had used that figure, and I knew that others had used that figure.

Seventy feet of porous pay production is an average figure. I obtained that figure from Mr. Peterson and discussed with him his opinion of the average thickness of pay in the field. He did not tell me that in his judgment the pay formations in that field had an average thickness throughout the field. He told me that in his judgment what he considered the best commercial producing areas of the field would probably average that in feet. That is the area enclosed within the reddish lines on Exhibit 13 and aggregating some 1,033,000 acres. He didn't tell me that it was his judgment that this area outside the reddish lines had pay thicknesses averaging 70 feet. I don't think he stated what his opinion was as to the thickness there; but when I applied that 70 foot thickness I applied it to the whole 1,475,000 acres. Mr. Peterson informed me that in the total field, and I assume that by total field he meant all of the area included within the red lines; in other words, what he terms the best commercial portion of the field—that according to his estimate the figure in the total area of the field was 70.01 and he used 70 feet. But in the west field, which constitutes by far the greater acreage of the whole field, according to his estimates and calculations the average thickness per acre was 72.98 within that commercially productive area and not including I would say the small area outside of those reddish lines shown on Exhibit 13. I think that the 432,000 acres would be a small area as compared with 1,475,000 acres. It is a smaller area than that which is included inside, aggregating 1,031,000 acres.

Notwithstanding the fact that Mr. Peterson did not inform me that in his judgment the average pay thickness outside the reddish lines was 70 feet, I used that figure as applied to the outside areas as well as the inside areas where he applied it. I used for the whole area an average of 70 feet. I did not use the 70 feet for the major portion of the field which is located within those red lines in the west field. Mr. Peterson told me how he got this 70 foot pay thickness in the area enclosed within the red lines. He showed me a little map which he had colored, in which he set out the areas included in the reddish lines and the other areas, one in yellow and one in gray.

(Map entitled "Texas Panhandle" showing best commercial gas area and marginal gas area, marked Exhibit 20 for identification.)

Exhibit 20 appears to be the same map which Mr. Peterson gave me, in which he set out in colors the area which in his judgment should be classified as best commercial gas area and the area which he classifies as marginal area. The portion colored in yellow on this small map I believe is the same portion as that included within reddish lines on Exhibit 13, and that portion which falls outside those reddish lines on Exhibit 13 is shown on Exhibit 20 in a gray color.

Mr. Peterson told me that the average sand thickness of the yellow, wherever found in the reservoir, was 70 feet. That was my understanding of his statement. The figure of 72 feet referred to by me was the weighted average thickness in the West field alone; but in arriving at his figure of 70 I assume he took into account all of the acreage including that in the East part of the field. If his average was 70, and the average was 72 in the west field, the average in the east field was substantially less than that, taking into account the size of the area.

90 Mr. Peterson told me that in determining that the sand thickness would average 70 feet throughout that area colored in yellow on Exhibit 20, he had combed over all the available information that he could get that indicated thickness of pay in the various wells that had been drilled in the field and by that method he got his basic information from which he computed this average. The way I understood it, this included logs and whatever other information he could get that he thought was reliable and authentic. I was sufficiently impressed with it that I adopted it as the basis of my own computation, after talk-

ing with him and finding out how he got the information. I was convinced that he had made a good job of it.

You inquire if it is not true that I did not apply it where he applied it in making computations. In the first place, I think his total acreage did not coincide exactly with the total acreage as set forth in the report of the Texas Commission. There is some difference there. As I understand the method used by Mr. Peterson, he applied in his calculation a certain thickness of pay as applicable to the area that he called the best commercial producing area; but how he determined the estimated amount of gas under the marginal acreage I didn't have time to go into, so I never found out. He had figures on this area marked "Best Commercial Acreage" varying from 33½ feet up to something over 92 feet in thickness, an average in the west field of about 73 feet and over the whole field about 70 feet. I have used his average of 70 feet. As stated, I didn't know just what he applied as the figure in the so-called marginal acreage. I knew that he had arrived at an average figure of 70 feet in the yellow part of the west field and the east field also. I took them both into account and arrived at an average of 70 feet. I assumed that at the time he gave me these figures he was not including the 432,000 acres which he has classified as marginal acreage on Exhibit 20. In my computation I used 70 feet as my judgment of the thickness for the whole business.

You inquire upon what I based that judgment. My answer is that I had these figures Mr. Peterson had used in determining his averages and I noted the variation between the various thicknesses he had found, and I noted the fact that he had arrived at an average of approximately 73 feet thickness in the west field, which is by far the largest area of the whole field, and I simply assumed that over the whole field area the 70 foot figure would be a fair average figure. When I say 73 feet in the west field, I mean in the yellow part of the west field. I have no information on the rest of it.

I stated yesterday I think that it was perfectly natural for the producing formations to pinch out around the edges and get thinner and less productive. I wouldn't say that it is just as natural as could be where you have an elevation or dome condition, with slopes off from this apex in different directions, with the water level down there coming in contact with that slope, for the producing part of the formation to be pinched out and thinned out as it

spreads away from that dome. There are conditions where the thickness of the formation might be less on the axis and the apex of the dome and be bigger along the
91 edges. As to whether that is the situation in the Panhandle, I could not answer that question. I have noted the cross section, Exhibit 16, from which one might draw the conclusion that it is true. However, a definite determination of that could only be made by a study of such well information as is available around the whole circumference of the area.

I don't know how long Mr. Peterson has been down in that field working on the problems that go with his profession as a geologist. He might have told me, but I don't recall. It is my impression he has been there a long time.

It would appear if the ideal cross section, Exhibit 16, were based on well logs showing the formation thickness of the porous portions of the traversed formations, then that some of the heaviest or thickest pay formations are right over the top of one of those granite domes. I did not mean to say that it would appear that the pay formation was thinner on top of the apex. What I meant to say was that from Exhibit 16 it would appear the reverse. I think I used the words "pinch out."

If the average of this yellow area was 70 feet, including all those yellow areas in the aggregate, under the conditions prevailing in the Panhandle some of it must have been thicker than 70 in order to have an average of 70, and there must have been areas even in the yellow where the thickness was less than 70 feet, if the average was 70. I don't believe that the figure of 73 or the figure of 70 is closely accurate enough to determine any reason why 70 should not be used over the whole area. In my opinion, the reason for that is that the west field, which includes the greater portion of the area of the entire Panhandle field and in which the area marked yellow constitutes a substantial portion of the total area of the west field, contains wells in which, from Mr. Peterson's data, the pay thickness varies approximately from 30 to 100 feet. There may be areas in the yellow area where the thickness is 150 feet. I haven't examined all of the logs of the wells in the field. I have examined a number of them and have well data taken from logs of a substantial number, largely in the west field. Many of them do not give conclusive evidence as to the thickness of the producing pay formations. Those that do show varying thickness.

You take the information that I went over in connection with Mr. Peterson's work and his results. He gave me information to the effect that he had gone over the relatively large number of wells in both the east and the west fields. For instance, in Carson County he noted 103 wells covering a gas acreage of 195,300 acres in which the average thickness of the producing formation per well was 85.82 feet. Another item was 16 wells in Potter County where the average thickness of the producing formation per well was 92.19 feet. A total of 87 wells in Moore County, where the average thickness of the producing formation per well was 78.21 feet. Also a total of 24 wells in Hutchinson County, where the average thickness of the producing formation per well was 61.67 feet. All of those that I have mentioned were in the sweet gas area of the west Panhandle field.

92 Mr. Peterson told me that when he got through with all of it the walls in that yellow area averaged 70 feet in thickness. That was the summation of what he told me, and I am just giving a breakdown of what I said a little while ago he told me. That is the source of my information concerning sand thickness in the Panhandle. I don't remember that he told me he had logs showing that some of the wells out in the marginal area had sand thickness as low as seven feet. He told me he had information on wells throughout these yellow areas sufficient to average all of these yellow areas together and in that way he had arrived at this 70 feet, based on well information and other information which he considered reliable. I cannot state with yes or not whether he told me that he did not have a sufficient number of wells with a sufficiently even distribution around the marginal area to average that area as he had the yellow area, but that he had broken it up into small areas where there was sufficient control by actual well information that he could classify it, and in his judgment it was properly classified as marginal, based on localities rather than an average all around because we discussed the question of sand thickness rather fully, and I gathered the information from Mr. Peterson that in his opinion he felt he had secured sufficient information on the wells drilled in what he termed the best commercial acreage to warrant his using, in his judgment, the figure of 70 feet and a figure for the west field of approximately 73 feet. As to the marginal area, it was my impression that Mr. Peterson indicated in his conversation with me that

he did not have enough data to make a similar conclusion as to that marginal area, but that he had used what he thought was a reasonable figure for the contents per acre of gas in that marginal area.

I don't remember that he told me how he got that reasonable figure. If he did so, I do not remember what his explanation was; but I got a very definite impression that there was some reason why Mr. Peterson was not willing to include this marginal area in the area where in his judgment the thickness was 70 feet. I gathered the impression that he thought the yellow area was the best. He also said that the yellow area was determined by him by including the area in which the open flow of wells was greater than five million cubic feet, and that the marginal area, as I remember him stating, was an area in which the open flow of wells was less than five million cubic feet.

In reply to the Examiner's question of whether Mr. Peterson used the 70 foot figure at all for marginal acreage, as I stated a moment ago, I do not know just how he arrived at the estimate of the gas under the marginal area. He may have modified it. I don't know how he used the 70 foot pay thickness there. I don't know just how he arrived at his per acre amounts.

I do not know that he told me there was any difference in the porosity and permeability in the marginal acreage and in the yellow or commercially better acreage other than as that would be indicated by open flow. I think what he actually told me was that from his research he believed that area included wells that produced less than five million cubic feet open flow. As to whether he told me that many of them produced down to a million or some of them even less than that, I do not remember that we had any definite figures on that.

93 I do not remember all of our discussion. The principal thing I remember was the differentiation between open flows. In other words, the wells included within the yellow area had open flows of five million and over, and those in the marginal area less than five million cubic feet. I think Mr. Peterson gave me the figures as to the quantity of gas he thought was contained in the marginal area. How he arrived at them I do not know. We did not have time to go into it. He gave me his estimate of the quantity of gas contained in the 432,000 acres, and his totals would indicate that he did not use an average pay thickness of

70 feet and a porosity of 20%. I disregarded those estimates and applied his factor of pay thickness and porosity over here in the yellow area clear out around the entire field, including the marginal acreage where he had rejected it. I would not know what the thickness and porosity are of the area immediately south of the barren spot crossing the line dividing the east field from the west field on Exhibit 20 in comparison with the rest of the field. I did not give it any specific thickness in making my computation, but averaged it in with the rest of it. I averaged it in with the yellow in which Mr. Peterson's judgment indicated to him and he told me that he thought it was 70 feet average.

Mr. Peterson gave me figures, which I used, showing the average thickness of the yellow area was 70 in his opinion, and I averaged those figures in with the marginal figures and got 70, which I applied as my result. I used 70 feet over the whole area. He did not say, as far as I know, that the porosity was not an average of 20% over the whole area. He used 20% for his yellow area and I used it for all of it.

I reached the result of gas in place in the gas acres to a 25 pound gauge abandonment pressure of 23,645,017,748 MCF—in round numbers this would be 23,645,000,000,000 cubic feet. By that I mean the original content down to 25 pounds gauge in pressure. By a 25 pound gauge I mean the amount of gas that would be in reserve which if moved will leave the average wellhead pressure at 25 pounds gauge. In other words, I am assuming that all of the wells could be produced down to an average of 25 pounds wellhead gauge in order to determine what gas there would be on that basis. By gas acres I mean the 1,475,324 acres designated as gas acres in the report of the Texas Commission. I mean the free gas or dry gas producing part of the reservoir, and that would include all of the colored area on Exhibit 12. Under that colored area there are some 100,000 acres that also produce oil from formations belows those producing gas.

I also gave the figure of 19,255,928,848 MCF at what I termed 100 pounds abandonment pressure. In that computation I used the 100 just like I did the 25 in the other computation, and figured the amount that would be recovered down to the point where the average pressure of all the wells would be 100 pounds at the wellhead gauge. I put in that second computation because in the discussion with Mr. Peterson he indicated to me that it was his opinion that

the company might have to go to 100 pounds abandonment pressure, by which I presume he meant that he had doubts about whether the company could economically produce gas in the Texas Panhandle and bring it to markets principally in Chicago when the pressures had gotten down below
94 100 pounds at the wellhead on the average. On that basis I put in the computation at 100 pounds abandonment pressure. By saying "I presume that that was true," I mean I presume that that was what Mr. Peterson meant rather than that the ultimate facts were true. I gathered that impression from him. I have no way of knowing exactly what was in his mind, but in our discussion I thought that I scented that thought.

In applying my estimates of the reserves I used a 100% recovery factor. I assumed that the gas in the well would be withdrawn down to a point where the wellhead pressure was 25 pounds gauge, and that the 25 pound pressure would then prevail throughout the field if you abandoned each well at that pressure and drilled up the acreage entirely. In other words, what I figured was the amount of gas in place between the initial virgin pressure and an ultimate abandonment wellhead pressure of 25 pound gauge, and I arrived at a certain amount which I stated. As to whether I made any allowance for gas that might be left in the reservoir in areas having higher than 25 pounds pressure when the average wellhead pressure gauged 25 pounds over the field, I assumed that the formation being porous, as it is, when the wellhead pressure got down to 25 pounds there very probably would be an equalization in the reservoir. I mean there would probably be equalization between the time of first production and the time these wells were abandoned. I am assuming that there would approximately be a reservoir pressure equivalent to a pressure of 25 pounds at the wellhead.

It does not follow that it is my idea that as time goes on these pressures will begin to equalize and that by the time they all get down to 25 pounds, if that be assumed to be the abandonment pressure as you have stated, that the pressures in the field will have equalized. They would equalize if they were abandoned and let stand; but at the time the well was abandoned there would probably be a differential in pressure. I am not assuming that every individual well that you own and operate will stand at 25 pounds exactly when you abandon it. My estimate is made upon that as a general abandonment pressure at the wellhead. It is prob-

able that when the general abandonment pressure at the wellhead for all the wells in the field at the time of abandonment reached 25 pounds the pressure out in the reservoir away from the wells would be temporarily higher than 25 pounds, but it would probably ultimately equalize.

I presume every company does not produce every well at all times, and in the actual practical operation of the production of gas in that field you could probably pull the well down to something less than 25 pounds and quit pulling from it and continue to pull from other wells as a practical thing. Practical business economics get into all of these things. During the latter part of this company's history it will have a great deal of difficulty in getting gas to fill its requirements from its present wells. If it is assumed that they drill twice as many wells, a well to every half section of the land they own down there, the time will come when they will not be able to get enough gas from those wells to fill the pipeline, which transports from 205 to 220 million cubic feet of gas per day. They are going to be very reluctant to operate a pipeline with any less gas than they now get out of the ground as a practical proposition. Other operators in the field will all be trying to get as much as they can, so it is very probable that everyone will be pulling as much gas from every well as possible in order to get as much gas in the line as they can.

When they get to the point where they cannot get enough to justify going on, and abandon these wells, if they are 100 pounds or if they are 75 or 55 pounds, the pressure away from the wells at the time they quit is going to be higher for a time than it is at the bottom of the well. If you want to bring in economic factors and things of that sort, I presume business judgment would probably seek other sources of supply prior to the time they were abandoned.

The thing that makes gas flow to the bottom of the well is difference in pressure between the pressure at the bottom of the well and the pressure out in the sand or the limestone. It is pressure differential. That is a very common term in my profession. It is the pressure differential that causes the gas to flow from the area out away from the well to the bottom of the well, and if the pressure is not higher out there than it is at the bottom of the well, there would not be any flow.

There is no question but that if you abandon a well at a given pressure, the pressures all around that well

throughout the area from which it has been producing its gas will be higher than at the bottom of the well. If the pressure at the wellhead is 25 pounds, the pressure at the bottom of the well would be about 40 pounds absolute, and the pressure out away from the well would have to be something more than 40 pounds.

(May 25, 1939.)

I stated that when the pressures at the wellhead reach a given or assumed abandonment pressure, the pressure at the bottom of the well is somewhat higher. The pressure at the bottom of the well is always higher than at the top. The difference between the pressure gauge at the wellhead and that at the bottom of the hole is the weight of the column of gas in the casing when the well is static or shut in.

I also stated that the pressure out in the reservoir away from the well is during the time of flow necessarily higher than at the bottom of the well. There has to be a difference so that the gas will move from the sand or limestone to the well bore.

You ask me to look at Exhibit 19 and visualize that part of the exhibit called A as the well bore of the well and assume that the pressure at the top of the well is 50 pounds gauge. If the well were shut in, the pressure at the bottom of the well would be the difference due to the weight of the gas column.

You assume that the pressure is 50 pounds at the top of the well and inquire if it is not true that the pressure
96 out away from the well radiates from the higher pressure due to the weight of the column of gas, which you assume as X pounds, or 50 plus X. You inquire if the pressure will not get higher as it gets away from the bottom of the well. It would during the flowing period. After the well is abandoned the bottom well pressure would probably equalize with the sand pressure. If X is the static head or if X is the static head less friction head, it would probably equalize and become higher than 50 plus X at the bottom of the well. If the wellhead pressure was 25 pounds, the bottom hole pressure would be more in any event in a static condition. If it was 50 pounds at the wellhead, it would be something more than 50 plus 15 because the gas would weigh more at 50 pounds than at 25. If X equals the difference between the pressure at the wellhead and the bottom of the well, then the pressure at the bottom of the well would be 50 plus X, if 50 is the wellhead pressure.

If it is assumed that 50 pounds is the abandonment pressure, the pressure along the reservoir will graduate from the bottom of the well at a higher pressure—higher pressure levels as you get away from the bottom of the well. As it stands shut in, it will equalize at some higher level than 50 plus X, depending on how much you pull the well. If you abandon the well at 50 pounds, when equilibrium is reached the bottom of the well pressure will be higher than 50 pounds, and the gauge pressure will rise to a point that would be equivalent to the bottom hole pressure, as well as the static column of gas between the bottom of the hole and the wellhead. When it equalizes you add the weight of the column of gas in the static condition to arrive at the pressure at the wellhead after equalization, and that would be more than 50 pounds, if you had started out with 50 pounds.

If the well is abandoned at 50 pounds and the owner goes off and leaves it, then the difference between that pressure of 50 pounds and that it has when equalized becomes lost so far as the operator is concerned, if he does not pull it again.

As to whether under the conditions in the Panhandle he can't shut his wells down and wait until the next month or the month after next and then go out and pull his well, as a practical proposition, I can only say that depends. Another thing, he would not have to stop, in my opinion, producing from the well at exactly 50 pounds there. He would stop at some abandonment pressure, but he might not stop at 50. He might pull it down to 35 and then maybe it will settle at 50.

Abandonment pressure is the pressure at which you abandon the well. It may or may no be the lowest pressure the wellhead shows when you stop pulling. In my opinion, it is perfectly feasible to assume that the abandonment pressure of a well, if it is 50 pounds, would be the pressure that would result on that well after it had been abandoned and had stood there.

I know that you can't produce gas from a well and at the same time have it shut down for the purpose of building up its pressure. I am not assuming that is done at all.

97 I assume that every operator in the field will produce just as much as he can—as much as the law will permit him to produce—in order to keep his outlet going and see that his carbon black plant is supplied. If it is possible

for him to produce to 50 pounds or to 35 pounds, in my opinion that is what he is going to do.

When the pressure at the wellhead is down to 35 pounds, the pressure at the bottom of the well will be something more than 35 plus 15. The figure of 15 pounds is the difference between the gauge pressure at the wellhead and the absolute pressure at the bottom of the well. I am not assuming or saying that the weight of that column of gas is 15 pounds. The figure of 15 pounds is the difference between the 25 pounds gauge pressure at the wellhead and the 40 pounds absolute at the bottom of the well. If you take 35 pounds gauge instead of 25, the difference will necessarily be more than 15 pounds.

If the figure of 35 wellhead pressure is taken, the figure at the bottom of the hole is more than 50 under static conditions. The pressure away from the well is then more than 50, gradating, as you leave the well, out toward some other well or toward the edge of the field. At the time you stop pulling it gets higher as it gets away from the well, and the high pressure curve as you leave the well depends on several things, one of which is the distance between this well and the next one. That is one factor. If the formation is tight or of low permeability, that also has a lot to do with how high the pressures are out between the wells. If the permeability is low, you have a higher pressure out away from the well than if it is high—the less permeability, the higher the pressure.

Another factor which enters into it in addition to the distance between the wells and the difference in permeability is the rate at which the well has been pulled. If you have pulled it at a rapid rate the gradient is steeper than it would be if you had been pulling it along at a very low rate. If everybody is pulling as hard as he can we will have steep gradients.

I question very much whether anybody can tell absolutely in a great area like that how much gas is going to be left between the wells under those circumstances. It is a matter of judgment, experience and conditions.

I have seen Exhibit 20, about which some questions have heretofore been asked me. I have seen the other larger maps on which the wells throughout the field are spotted. It is true that in the area colored yellow on Exhibit 20 a great many more wells have been drilled than out in the outlying gray area. I made the statement the other day that it is perfectly natural that wells are going to be drilled

where the production is highest in the development of the field; but that depends entirely upon policies of management of those who are operating the property. I had not intended by that statement to mean that there is anything to prevent the management of an operating utility or property from drilling wells anywhere he wants to on his
98 property. In my opinion that is entirely a question of judgment and management. An operator may drill some wells out where there is little gas to find out what he is going to get; but he is going to use his own judgment in drilling.

You inquire whether in the exercise of ordinary prudence and reasonable business judgment there will be many wells drilled out in the thinly supplied area colored in gray, or the area of low productivity, and whether there will be as many wells drilled out there per acre or per hundred acres or per thousand acres as in the yellow area where the production is heavier. Let me answer that question in this way. There are more wells drilled in the yellow area. The edge area that you refer to, the thinly supplied area, the area of low productivity—I am not so sure that it is an area of low productivity or that it is an area thinly supplied. It is true there are fewer wells in the perimeter around that field, but I don't subscribe to the statement that that is a thinly supplied area.

You ask how I account for the fact that there is not a well in the gray area which has as much as five million cubic feet a day, whereas there are wells in the central portion which have from one hundred million or more. My answer is that there may be a difference in the permeability of the structure. I did not the other day use the expression that it was perfectly natural for the field to feather out. The record will show the expression I used. I remember having used the phrase "pinched out," which in my opinion is quite different from feathered out. From the various information that I have and that I have seen and literature that I have seen, and statements that I have seen as to this field by geologists who should know what they were talking about, it is reflected that the thickness of this lime and dolomite increases as it dips basinward. It does not necessarily come to a point as it dips basinward where it is not one-half inch wide.

You ask if there is not a thin area so far as production of oil or gas is concerned between the portion on the producing flank of the mountain and the formation where it

gets to the water at the edge. My answer is that the thinness of it is relative. It would depend on the pitch or the angle at which that formation dipped, and it would further depend upon the thickness of that formation as it entered the water. If the formation increases in thickness as it dips basinward, then there is no thin measure for a very long way, particularly if the pitch is steep. The slope varies down through that structure at different places. From the cross sections I have seen it appears to have a varying slope at varying points. In some places the slope is less than in others. I don't know whether the logs in various places show that there is a sand thickness down to seven feet.

(Objection by Commission; Counsel overruled.)

You ask me the name of some geologist who told me that the sands are thicker at the perimeter of that field than they are in the center of the field. I mean I read it in a paper by Cotner & Crum. It is No. 8, Bulletin of Petroleum Geologists. I didn't say that they said the pay thickness is thicker out on the perimeter than it is in the middle. The statement on which I relied in answering the question is in there. I will find it if you want me to.

99 As to whether the wells out in the gray area have not been large producers, whether that fact is due to the thinness of the pay or to poor permeability, or whatever it is due to I will state that that is Mr. Peterson's hypothesis. I don't know of any wells that have been drilled in the gray portion that have potentials over five million cubic feet; but there are wells in the yellow, pretty near to the gray, which have very high potentials. Those wells are included in the averages made by the average of 73 feet in the west field. I used 70 feet over the entire field.

You ask whether it makes any difference to an operator who is going to spend his money in drilling a well that his failure to get a commercial quantity of gas is due to permeability or low pay thickness. My answer is, generally speaking, no.

You ask me if it is my judgment, as a man who has been connected with a regulatory body for a good many years, that there will be as many wells drilled on an acreage basis in this gray portion of the field as up through the yellow territory shown on Exhibit 20. (Objection by counsel for Illinois Commerce Commission overruled.) As I understand the question you are asking me whether or not in my opinion there would be as many wells drilled, or there

will be as many wells drilled, per acre in the gray portion of that map on Exhibit 20 as in the yellow. I don't know. Certainly at this time there are less wells over on the marginal area than there are in the central area. What will be done in the future I don't know. I just don't have any judgment about the future.

I have thought of all the factors I could which are calculated to cause gas to be left in the formations at the time the abandonment of the field is reached. You say I said something about wells having gone dead at pressures around 150 pounds. The record will speak for itself as to what I said. If I may be permitted to try to repeat what I said, I asked Mr. Peterson of your company whether or not any wells had been abandoned by Texoma, and he said yes. I don't remember how many he said. I remember there were several. I know I got that impression. I asked him whether or not those wells had been abandoned due to the depletion of pressure, and my impression is that his answer to me was to the effect that that was not the factor that caused abandonment, but that abandonment was necessary due to some other factor, which I gathered was some mechanical or physical condition. I don't think he told me that the pressures averaged around 150 pounds the last time they were taken before the wells were abandoned. I don't believe I made a definite statement that they were abandoned at 150; but my impression is that the pressures were substantially over 100 pounds.

You now refer to Exhibit 16 and point out perpendicular black lines extending along the irregular part of the drawing called the surface, down through the various formations where you assume to be oil wells. You also suppose that well No. 5, reading from the right, had been drilled and instead of stopping at the bottom of the oil pay it had been drilled on further and encountered water. You ask whether there is any possibility of that water getting up into the gas pays. The only possibility that I can see
100 would be if the bottom of the hole were open to the water and the pressure on the casing string was reduced to such an extent that the pressure at the bottom of the hole would allow the water to rise up. Then if the casing is perforated or leaky, or was not properly cased off or cemented off where it passes through the gas measures, it could.

You also assume that the casing is up above the gas pay so as to produce gas from the well, and that the hole is open

from that point down to the water, and ask whether the water will get up there. My answer is it would not because I assume that you have pressure there in the gas producing horizon. There would be some gradient to it.

You ask if I know whether the water does rise when the well is drilled down to water and the casing set above the gas pay. My answer is that I have never seen one do it. You are taking well No. 5. You have assumed the casing is set out above this red line, which I understand represents the gas producing measures, and that the hole is drilled down through the water at approximately sea level. This water at approximately sea level will rise in the casing up to the point where there is a pressure balance between the column of water and the pressure in the casing. Now, if the casinghead were wide open so that the differential in pressure between the water and the top of the hole were high, the water column would rise to some point at equilibrium. If that well were shut in absolutely, it is probable that the water would not rise up there very far, if at all. You do not keep oil wells or gas wells shut in, as a practical proposition, nor do you leave them open to the water. You should plug them off. It is possible that the reason for plugging them off is that if they do not plug them the water will rise and seriously damage the oil formation and the productive gas formations above.

I neither agree nor disagree with your statement that there was a great deal of careless plugging of wells in the early history of that field due to the fact that nobody thought anything particularly of the gas that was down there. I do not know whether that occurred or not. If it should turn out that there was a lot of careless plugging or that the plugs, due to the physical reactions down in the formations where the plugging was placed, had become leaky, I would expect some water to get in the well bores and come up. It is also possible that water might leak in from some water formations which were drilled through and cased off up between the dolomite and the surface. If it were not properly cased off at the place where they went through it, it would run down the well bore and get into the producing formation. I don't know whether that has occurred in the Panhandle.

At your request I read from page 43 of the 1938 report of the Railroad Commission of Texas, under the caption "Gas Wells Producing Water," the following:

"The following information was obtained by Commis-

sion engineers and field men during the potential and rock pressure survey of June, July and August, 1938. All wells that were producing water at the end of twenty minutes
101 potential test period were considered to be producing intruded water and not accumulated water condensate on the theory that any condensate in the casing would be dissipated before the expiration of a twenty minute period.

"During the March, 1936, survey, samples were taken from eighteen wells and then analyzed for salt concentrations. Of the eighteen samples analyzed, only one was diluted with fresh water, the remaining seventeen being bottom or edge water."

On pages 44; 45, 46, 47 and 48 appear listings under the caption "Gas Wells Producing Water. The Entire Panhandle." There are five pages, closely written, with different captions for different counties. There are 46 wells on the first page. There are different numbers on different pages.

I cannot say definitely whether Mr. Peterson told me the reason the wells went dead was that water came through from the top or the bottom and drowned out the producing formations. It is possible that he did. We didn't discuss it very much, but I gathered the impression that there was some reason, either mechanical or water or some other reason than a depletion of pressure, that caused the abandonment of those wells. That is as far as I went.

As to whether the pressure in the formation would tend to keep the water back so that it would come up against the resistance offered by the pressure of the gas, I will say that would be true as regards bottom hole water, if and when the wells were shut in. If the wells were producing, the pressure would be less. I don't think the danger of water coming up from the bottom would be increased as the general pressures of the field go down. I think the reason for bottom hole water getting in is the failure of the seal at the bottom of the well. That plug may be made of different things. It may be made of cement or wood. I never saw any plugs in the Panhandle.

It is true that these cement plugs or wood plugs are subject to deterioration as a result of the lapse of time due to the chemical elements that are in contact with them down there in the formation two or three thousand feet below the ground. They are subject to the same

forces and conditions of nature as anything else down there. Even though the water was successfully plugged off for a time, it is entirely possible that the plug will be so corroded or so affected by chemical reaction that it would begin to leak water later on. There might be corrosion of the casing. That corrosion continues to take place as long as the well is there, and the degree of danger or hazard of the corrosion permitting water to enter the gas bearing formation depends on the conditions as to the chemical reaction between the casing and the elements.

The damage resulting from the intrusion of water into the formation would not be confined to the particular well through which it comes up the formation, but it
102 may spread out to where other wells are. Thus if you take the group of wells 3, 4 and 5, reading from the right, the water coming up through No. 5 and getting into the formation, if it is sufficient, might spread down the formation and destroy wells Nos. 3 and 4, even though they were not drilled into water at all. It is not impossible to flood a formation.

I doubt whether there is any great probability of the trapping off of gas under the physical conditions that exist in the Panhandle if that kind of flooding takes place to any considerable extent. I have heard of the hazard of water encroachment or edge water. I don't think the wells in the Panhandle are any worse or any better than they are in many other fields in the country. I don't think the hazard is any greater or any less than it is in the average field.

You ask whether in estimating reserves of gas down to a given or assumed abandonment pressure it is the common practice of men who do that sort of thing to apply a recovery factor to compensate for gas that will be lost by reason of a differential of pressure out through the field when the wells reach their abandonment point, and for the gas that is going to be left in the field due to lower permeability, and gas that is going to be left in the field due to entrapment or for any other cause. My answer is that some engineers and geologists use such a factor. As to whether the Bureau of Mines use this practice, I can only say that from the estimates which they have made and which I have seen they have used no recovery factor. I have not seen them all. I have seen

some of their estimates covering the Panhandle of Texas. I am not at liberty to divulge what report that is. It is not a public document. I have seen figures from the Bureau of Mines that I am not at liberty to divulge into this record on this occasion. The Bureau of Mines have published reports; but this is not a published report.

I do not remember having seen a report of the Bureau of Mines dated July, 1936, R. I. 3313, Department of the Interior, United States Bureau of Mines, dealing with the horizon of central Michigan. You have now exhibited that document to me. I glanced at it but have not examined it carefully. I didn't see where they applied a recovery factor in making their estimates of gas in the Michigan field. You have asked me to read the last paragraph on page 9 of that report. (Objection by Commission counsel and counsel for the Illinois Commerce Commission overruled.)

I am reading now at the request of Mr. Morgan, company counsel, from a publication marked R. I. 3313, dated July, 1936, by the Department of the Interior, United States Bureau of Mines, John W. Finch, Director, entitled "Report of Investigations. Extent and Availability of Natural Gas Reserves in Michigan 'Stray' Sandstone Horizon of Central Michigan," by E. L. Rawlins and M. A. Schellhardt. I have been directed to read a paragraph on page 9 of that report, which is as follows:

"Correction Factor.

"An analysis of different factors as applied to the Michigan stray sandstone horizon in relation to the histories of gas production from fields of other states 103 indicates that possibly 90% of the total volume of gas calculated from the gas-reserve formula can be produced from the reservoir space if the wells are completed properly and gas is not withdrawn from them at an excessive rate of flow." (Objection by Counsel for the Illinois Commerce Commission on ground that reading unidentified report on cross-examination not proper was overruled.)

You ask me to turn to page 17 of that same report and look at the tabulation beginning near the top of the page and extending down to about the middle of the page, showing that in computing these reserves they computed both the quantity before applying a correction factor and then the correction factor at four different pressures, 15,

50, 125 and 200 pounds. (Objections by Commission Counsel and Counsel for Illinois Commerce Commission overruled.)

I think in reading from this page it might be proper to read the entire table or paragraph there so that the record will show really what it is.

On page 17 of the publication marked R. I. 3313, dated July 1936, by the Department of the Interior, United States Bureau of Mines, from which I just read another paragraph from page 9, appears a table marked "Table V.—Summary of Gas Reserves, Clare Field."

"Producing area, acres 710.

Average thickness of pay member, feet, 4.

Porosity, per cent, 20.

Initial wellhead pressure, pounds per square inch gauge, 600.

Initial reservoir pressure, pounds per square inch absolute, 635.

Temperature in reservoir, Fahrenheit 64.

Deviation from Boyle's law at reservoir pressure, per cent 10."

Then appears a tabulation which consists of 11 columns. The first column is headed "Abandonment pressure at wellhead, pounds per square inch absolute." In that column there appear four figures. The first one, or rather the first, includes abandonment pressure at the wellhead on an absolute pressure basis, 15 pounds. The next is 50 pounds. The next 125. And the fourth is 200 pounds.

The next column is entitled "Reservoir Abandonment Pressure, pounds per square inch absolute." That column likewise contains four entries. Opposite the four entries in the first column the figures in the second column are as follows: 15 pounds abandonment pressure absolute in the reservoir; the next figure is 52 pounds absolute; the next, 128 pounds absolute; and the fourth one 206 pounds absolute.

The third column is headed "Deviation from Boyle's Law, per cent." It also contains four entries which are opposite the four entries in each of the other two columns. The first figure in this column is zero; the next figure is 0.5; the next figure is 1.6; and the fourth figure is 2.6.

104 The next two columns have a common heading as follows: "Initial reserves pe acre foot thousand cubic feet." That caption covers the next two columns. The first of the next two columns, or the fourth column from the left, has an individual caption of "Correction factor not applied." The four figures entered in that column are as follows, reading from the top to the bottom: 410.7; 388.0; 341.3; 292.5. The fifth column with an individual caption as follows, "Recoverable," likewise has four entries, reading from the top to the bottom, as follows: 369.6; 349.2; 307.2; 292.5.

That covers the first five columns of the tabulation. The next two columns, namely, the sixth and seventh columns, have across their top a common caption as follows: "Reserves initially underlying total 40 acre gas producing tracts, thousand cubic feet." The sixth column, or the first of the two columns, which have the common caption that I just read, has an individual caption reading as follows: "Correction factor not applied." This column likewise has four entries, reading as follows, from the top to the bottom: 378,000; 357,000; 314,000; 269,000. The second of the two columns covered by the common caption, which column is the seventh column from the left and which has individual caption at the head of it as follows: "Recoverable," likewise contains four entries: 340,000; 321,000; 283,000; 269,000.

The next two columns, or the eighth and ninth columns, reading from the left, have likewise a common caption over both of them, reading as follows: "Initial proved and semi-proved reserves, thousand cubic feet." The first of these two columns, namely, the eighth column from the left, has an individual caption reading "Correction factor not applied." The figures entered in that column are as follows: 1,166,000; 1,102,000; 969,000; 831,000. The second column in that group, namely, the ninth column in the tabulation reading from the left, has an individual caption over the top, reading "Recoverable." The four figures as set forth in that column are as follows: 1,049,000; 992,000; 872,000; 831,000.

The tenth column of this tabulation, reading from the left, has the following caption at the head: "Withdrawals, thousand cubic feet." All four of the entries in that column are 70,000.

The eleventh, or last column, of that tabulation has

the following caption: "Net proved and semi-proved reserves, thousand cubic feet." It likewise contains four figures which, reading from the top to the bottom, are as follows: 979,000; 922,000; 802,000; 761,000.

There appears at the bottom of that tabulation the following notations: "Recoverable gas reserve estimates for abandonment pressure of 15 and 50 and 125 pounds per square inch based on a correction factor of 90 per cent." The second is "Withdrawals to February 1, 1936." The third is "Gas volumes expressed on pressure base of 14.4 pounds per square inch at temperature base of 60 degrees Fahrenheit.

The Examiner having inquired of counsel whether the table contains a note specifying what the correction factor is from the standpoint of definition, and counsel having replied "90%," and requested me to define what 105 is meant by recovery factor. I will say I am not in a position to say what is meant in that bulletin by that term. I would say that in my opinion generally a recovery factor is a percentage which when applied to a certain estimated quantity of gas or fluid in place would represent, in the judgment of the person who used it, the percentage of such fluid or gas that might be recoverable.

Counsel has requested me to read the following from said document. (Objections by Commission Counsel and Counsel for Illinois Commerce Commission overruled.) I am now reading from page 9 of the document marked R. I. 3313, and dated July 19, 1936, the same being a publication of the Department of the Interior, the United States Bureau of Mines, the caption of which I read some minutes ago and from which I read a tabulation and a part of a paragraph at the request of Mr. Morgan, company counsel. I now read from page 9 of the same report, as directed by said counsel and the Examiner sitting in this case:

"The writers believe that commercial production of gas from most of the central Michigan fields will not be feasible at less than an average field abandonment pressure at the wellhead of 125 pounds per square inch absolute if the delivered capacities of gas wells continue to decrease with depletion of the gas reserves as indicated by back pressure tests that have been conducted at different times in the productive lives of representative wells, and, therefore, reserve estimates are given in this report based on this abandonment pressure."

I note that that is an abandonment pressure of 125 pounds absolute.

I am not familiar with the publication captioned "United States Bureau of Mines. Oklahoma City Gas Reserves." "No. R. I. 3217, dated June, 1933," and further styled "Department of Commerce, United States Bureau of Mines, Scott Turner, Director. Report of Investigations. Estimate of the Gas Reserves of the Oklahoma City Oil Field, Oklahoma County, Oklahoma." (Objections by Commission counsel and counsel for Illinois Commerce Commission overruled.) I am not acquainted with the Oklahoma field as a matter of general information. I understand that it is a field which produces both oil and gas; but I am not familiar with its features or its conditions. It is my understanding that it is one of the largest oil fields and that it is also an important gas field. I have no direct knowledge. You have asked me to read from pages 3, 4 and 5 of that document. (Objections by Commission counsel and counsel for Illinois Commerce Commission and after colloquy between counsel and Examiner, the Examiner ruled he had a right to take judicial notice of the unidentified report.)

I am about to read some paragraphs under the instructions of the Examiner and company counsel and over objection of Commission's counsel from pages in the report numbered R. I. 3217, dated June, 1933, entitled as above set out:

"An estimate of the gas reserves in a field involves consideration of a number of variable and unknown quantities. To reach a solution, it is necessary to assume correction factors that depend largely upon the amount and
character of the information available for analysis,
106 probably reservoir conditions, and a knowledge of re-
covery values in other fields that are nearing exhaustion. The formula given does not include such factors as variation in sand porosities and permeabilities, water encroachment, possible development of oil in formations that contain free gas higher on the structure, methods of development, and specific information on different gas horizons obtained by the detailed analyses of individual wells and the field as a whole."

The paragraph that I just completed reading is on page 3 of this report. Starting at the bottom of page 4 of this same document, I read from the document as follows:

"This report presents gas volumes determined from the

study of the gas reserves of the Oklahoma City field as follows:

"1. The total original volumes of gas in the reservoir space that would be available above abandonment pressures of 100 and 400 pounds per square inch gauge at the wellhead, if it were possible to recover all of this gas.

"2. The original recoverable volume of gas, using a recovery of 50%, at abandonment pressures of 100 and 400 pounds per square inch gauge at the wellhead.

"3. The volume of gas withdrawn from this reservoir space previous to October 1, 1932.

"4. The net recoverable volumes of gas, using a recovery of 50% at abandonment pressures of 100 and 400 pounds per square inch gauge at the wellhead available after October 1, 1932."

You ask me if it is not the ordinary thing in computing gas reserves to allow some recovery factor. My answer is that some people who estimate reserves set out as a percentage or figure a recovery factor. Other people in estimating gas reserves may probably consider that the accuracy or limits of accuracy of certain factors used in the estimates probably include factors comparable and similar to recovery factors as such. (Objection by Commission counsel and question unanswered.)

In referring to some contours shown on Exhibit 12 just south of that portion of the gas field lying in Potter County, I have referred to the helium dome in the Texas Panhandle. I referred to a fault, by which I meant that it would appear the formations were at different levels. My understanding is that the helium dome, or Bush Dome, as I believe it is called, is under the control of the United States Government. I wouldn't say for certain that it owns it. It appears to be a comparatively small area as compared with the great Panhandle gas field proper.

107 I do not know what branch of the United States Government operates the helium property. I don't know if to be a fact that it is operated by the Bureau of Mines, of the Department of the Interior. I have heard that. I am not familiar with what took place when the Government acquired that reserve of gas. I do not know whether they resorted to condemnation proceedings or not. (Objections by Commission counsel and counsel for Illinois Commerce Commission overruled.) You state that condemnation proceedings involve taking by legal proceedings a property for public use and a payment to the owner

of just compensation for the property as the consideration for the taking. That coincides with my understanding of the term. I am not familiar whether the Bureau of Mines in condemning the helium dome which faulted off from the Panhandle gas field used a recovery factor of 60%. (Objection by Commission counsel overruled.)

You refer to the bulletin of the American Association of Petroleum Geologists, dated August, 1933, which was by Victor Cotner and H. E. Crum, and ask me to read the paragraph under the caption "Acknowledgment". (Objection by Commission counsel overruled.)

I find that the note at the bottom of the first page of this article contained in a publication entitled "Geology of Natural Gas," edited by Henry A. Ley, and dated 1935, according to page 385 under Note 1, reads as follows:

"Presented before the Association at the Oklahoma City meeting, March 24, 1932. Manuscript received March 10, 1932. Reprinted from bulletin of the American Association of Petroleum Geologists, Volume 17, No. 8 (August, 1933). (Paragraphs 877 to 906 in slightly revised form 1935.) The following geologists have contributed material or criticism in the preparation of this paper, to all of whom the writers express appreciation: L. M. Oles of the Prairie Oil & Gas Company; J. D. Thompson, Jr., consulting geologist; W. E. Hubbard of the Humble Oil & Refining Company; T. F. Newman of the Skelly Oil Company; Frank T. Clark of the Empire Gas & Fuel Company; and Richard W. Camp of the Consolidated Gas Utilities Company."

There are drawings in that document. (Objection by Commission counsel overruled.) At your request I read from about the middle of page 401 of this volume from which I quoted, as follows:

"The producing area of the Texas Panhandle field is estimated at approximately 1,300,000 acres. (3) Of this amount 100,000 acres have been drilled for oil production, although this has not been fully drilled up and may not all be productive of oil in paying quantities. Of the total gas area that part of which initial volume of 10,000,000 open flow per acre or larger may be expected consists of approximately 896,500 acres. Initial volume contours of the field would show that a belt of small volume extends around the outer edge of the producing area. Some small areas of less than 10,000,000 volume exist within the larger open flow areas, being due to porosity factors previously

mentioned." (Objection by Commission counsel and question unanswered.)

108 In my direct examination I computed the original reserves of the area colored in yellow on Exhibit 13, which I described as the gas reserves of Texoma. In computing those reserves I took the average per acre content which I used as the basis for my computation of the whole reserves. That figure was 16,027 MCF per acre, to a 25 pound assumed abandonment pressure. I multiplied that number by the number of acres contained in Texoma's reserves and tagged that as my estimate of Texoma's original reserve. I then arrived at an estimate of Texoma's present reserves on the basis of a 25 pound abandonment withdrawal pressure. I arrived at that by deducting the total withdrawals from those acres—the total quantity of gas produced from those acres by Texoma. I took the figure furnished me in response to a request that I made while in Amarillo for the withdrawals from the wells now existing on the present acreage of Texoma in making my request. I didn't use the word "production"; I used the word "withdrawals." The difference between the total withdrawals from the wells and the production by Texoma is substantial. I assume that the figures furnished me were in response to my request and that they constitute the withdrawals from the wells on the present acreage.

In computing the original reserves of Texoma I used the average sand thickness of 70 feet which I applied to the field as a whole. I thought that would be more fair and consistent than to use the figure of 73 feet developed by Mr. Peterson because I had used an average of 70 feet over the whole area. My understanding is that Mr. Peterson's 70 foot thickness was an average thickness of all the producing territory included in the yellow portion of a map that he showed me and which is now marked Exhibit 20. I used the 70 foot thickness as applying to Texoma's properties which for the most part are through the area I have described as the central axis of the field, although they do encompass some properties nearer the edges of the field itself. My reference to that portion of the field as being the most productive is that portion where the greater number of gas wells are located along the line and connected to the lines of Texoma and other companies operating therein.

In view of the fact that I am of the opinion that this lime and dolomite thickens as it plunges basinward, I am not

of the opinion, and I want definitely so to state, that the greater portion of the gas is located along the central axis.

As to whether I have heretofore said that the portion of the field alongsthe central axis originally contained a very much larger volume of gas than the outlying portions of the field, I would like to see the record on it. (Objection by Commission counsel.) I don't remember my statement exactly. I would rather have the record speak for itself, because it is not my present conviction that that is a fact, and I stated my conviction just now. I quoted Cotner and Crum in substantiation of it. I didn't read everything they said when you instructed me to read certain paragraphs. There is not at this time anything else in that report that I would like to read in connection with my statement based on Cotner & Crum. (Objection by Commission counsel overruled.)

In computing the original reserves of Texoma and deducting the production from the wells of Texoma and thus arriving at my estimate of the present reserves, I did
109 not take into account any drainage from Texoma's properties in the northeast over in the direction of the low pressure area portrayed on Exhibits 12 and 17. I did not assume that all the gas that was ever under those properties is still there except what has been drawn from the wells on those properties. As to how I could arrive at the estimate of the present reserves by that process unless I did so assume, I will say that my reasoning was that if there had been drainage from the reserves of Texoma toward the northeast flank of the field, there had also been drainage to Texoma's reserves from contiguous areas. I would not say in identieally the same quantities, but substantially in the same quantities. It is on that assumption that I arrived at that figure.

I do not know the initial pressure of the wells which Texoma has drilled. I used the same figure that Mr. Peterson used in his estimates of the natural gas reserves in the best commercial areas, as he designates them. I used an initial pressure of 430 pounds gauge wellhead to determine the original reserves under the presently owned acreage of Texoma.

I made no statement as to the number of wells which Texoma has drilled on its property, and do not know the approximate number. If Texoma's wells first came in at a pressure less than 430 pounds at the wellhead, that would indicate nothing to me. I presume that those wells would

have some drainage effect on that property. There is bound to be. I am not assuming that there will not be drainage. What I am assuming is a virgin pressure of 430 pounds at the wellhead. (Objection by Commission counsel.)

I stated in answer to a former question that I assumed that substantially all the gas that was drained out from Texoma's properties was very probably replaced by gas drained in from adjoining properties.

You are quoting me right in stating that in my opinion 25 pounds gauge pressure at the wellhead is a reasonable abandonment pressure for the purpose of computing Texoma's reserves. I stated that I was basing that partly on statements made to me by certain pipeline companies who owned properties in the Panhandle. I asked them for the information. This is a sample request: "Please advise by wire collect wellhead abandonment pressures you use in calculating gas reserves of your leases in the Texas Panhandle field." As to whether they were talking about abandonment pressures at which it would become uneconomical to operate the wells or whether they were talking about it from the standpoint of physical impossibility of producing gas when they answered that question, I assume they replied to that question by giving me their best judgment as to what they would consider an abandonment pressure in any connection.

I know as a matter of fact that the establishment of or the arrival at an abandonment pressure for gas wells in the Panhandle involves more engineering than geology. The actual abandonment pressure of a well would be a
pressure below which the operator or the owner would
110 not feel justified in going. That abandonment pressure might depend upon a great many things. As has been mentioned in the record in this case, for instance, mechanical difficulty and other factors. The abandonment pressure cannot of necessity be a definite, common, uniform pressure, due to those things. It is just a common sense business proposition; but in the estimation of reserves it is necessary to assume some abandonment pressure. In assuming an abandonment pressure it is not my opinion that I am assuming that every well will be brought down to that pressure and then locked up. Some of them may be brought down below that, some of them higher than that; but for purposes of estimating the recoverable gas in gas reserves, such as we are talking about here, we

have to reach some conclusion. In my estimates I have used two figures: a figure of 25 pounds and a figure of 100 pounds. I did that for the purpose of trying to have the record contain some range or some difference to make up for the fact that any company operating in this field, or any other field, may, and probably will, encounter difficulties in numbers of wells.

The evidence might disclose facts which would place the figure entirely one way or another clear outside that range of 25 to 100 pounds. I am not trying to testify here that the abandonment pressure of the wells of Texoma will ultimately prove to be a certain definite thing. I am only trying to use reasonable judgment. In my former statement when I said that I believed 25 pounds is a reasonable figure to use, I was talking about the reserves of everyone in the field. It is perfectly possible that the abandonment pressure of Texoma might be entirely different from the abandonment pressure of some other operator operating under entirely different conditions. My information from the Texas Railroad Commission is that at least one operator is contemplating pressures down to vacuum. (Objection by Commission counsel sustained.)

You ask me if it is not conceivable that the gas company which is producing gas in the north end of Potter County and taking it 40 or 50 miles to the town of Amarillo would have an entirely different abandonment pressure at which it will cease to produce gas and withdraw from the field than Texoma would have, in view of the fact that Texoma produces gas in the Panhandle of Texas and delivers it 900 or 1000 miles away. The difference between the two operations consists largely of one of pressures. I believe there is a difference in that regard, for the reason that the gas produced and delivered to the Fritch station of Texoma, under the present method of operation by that company, must be raised from the suction pressure to a delivery pressure approximating 700 to 750 pounds, let us say, whereas the gas produced at the point you indicated on Exhibit 17 may be produced and delivered at lower pressures, due to the fact that it has much less distance to travel. There is a good deal more friction between delivering gas from the field to Chicago than there is in transferring it from the field to Amarillo.

As to whether I gave any consideration to the number of wells Texoma would have to drill, the expense of operating those wells, the number of compressor stations which would

have to be built in the field, the expense of operating those compressor stations, or any of the economic factors
111 entering into it before making my estimate of the abandonment pressure for Texoma's properties, I will say that I did not make any economic studies or attempt to make any estimate of the necessary expenditures to be made by Texoma in the future, at this time. I assumed that very probably the same type of expenses and expenditures and development would have to be made by other pipeline companies that deliver gas for long distances, and it was indicated to me that in their opinion 25 pounds was a reasonable abandonment pressure. Some of them gave 50 pounds as an abandonment pressure, and I so stated on direct testimony. I included both 25 and 100 in my estimate; but I said that in my opinion 25 pounds was a reasonable figure.

As to how much gas a twenty million cubic foot well, coming in at a pressure of 430 pounds at the wellhead, would make when its pressure is reduced to 25 pounds gauge at the wellhead, that would depend a great deal upon the formation. It would depend entirely upon the open flow. It would depend upon the condition of the well. It would depend on the back pressure which the well is producing against. I can figure it out. I can't tell you offhand, but it is a thing which can be done by calculation. I certainly think that the quantity of gas that Texoma can produce from its wells has something to do with the point at which they will abandon the operation of those wells.

I testified that I graduated in mechanical and electrical engineering from the University of California, and studied petroleum geology in the University of Southern California. I was a student in the field of petroleum geology a few months in an extension course extending over a period of about three months. As to whether we met once a week, I don't remember how often we met. It might have been that and it might have been oftener, I don't remember; nor do I remember how many lectures I attended in the aggregate in that course.

(Colloquy of Examiner and counsel on subject of previous rulings allowing reading of unidentified document into the record.)

112 V. E. COTTINGHAM, a witness for defendants, testified as follows:

Direct Examination by Mr. Morgan.

(May 25, 1939.)

My name is V. E. Cottingham. My legal residence is San Angelo, Texas. My profession is that of petroleum geologist, in which profession I have been engaged since 1920.

I have a degree from the University of Oklahoma School of Petroleum Geology, and did postgraduate work in that school for a year and a half after I obtained my degree. My major work was in the field of geology, and my postgraduate work was in the same field.

I have been continuously employed in the oil and gas industry since the spring of 1921. I was first employed by Mr. William Cheney, in Oklahoma. I worked for him approximately sixteen months, and then went with the Empire Gas & Fuel Company. I worked in the valuation department of that company in Bartlesville, Oklahoma, later going to Eldorado, Arkansas, as district geologist, having charge of the geological work in Arkansas and Louisiana for the Empire. I then went to the central part of Texas, along the Balcones Fault area, and later established an office for the company at San Angelo, Texas, in the summer of 1924. In the fall of 1924 I left the Empire and went with the Shell Petroleum Company, establishing an office for them at Carlsbad, New Mexico. I had a district comprising southeast New Mexico and extreme West Texas. Later that district was consolidated with the San Angelo district, and I took charge of their office and remained there for approximately a year, after which I went with the Exploration Company, a local company. I stayed with them approximately 18 months as chief geologist. I resigned from that position and established the firm of Cottingham & Bristoe, consulting geologists, and I was in that type of work until I started with the Railroad Commission of Texas September 1, 1931, when proration became a function of the State of Texas.

I started with the Commission as deputy commissioner. At that time they had no engineering department. I continued as deputy supervisor until June, 1935, at which time I was appointed chief petroleum engineer for the Railroad

Commission of Texas. I held that position until October, 1935, and from that time to March 1 of this year I carried the title of director of production in charge of engineering.

While serving as deputy supervisor for the Commission, my duties were for nine months in the East Texas field, principally as a conservation agent. I came in contact with general operating problems during that particular nine months period. I was not supervising the railroad end of the Railroad Commission's activities. My experience
113 was all in the oil and gas division. In speaking of the East Texas field, I do not mean the East Panhandle field. The Panhandle field is divided into East and West fields. I refer to the oil field located in the northeast portion of Texas, in Gregg, Upshur, Smith and Cherokee Counties, as being the East Texas field. This is approximately 500 miles from the Texas Panhandle field. For the last three and a half years with the Commission my duties embraced the entire State of Texas. I have been in the Texas Panhandle and out in the field there many times. I have studied the logs of wells in the Panhandle.

(Request by Commission counsel to make preliminary examination of witness on qualifications denied.)

You state that there has come into this record the expression "weighted average pressure in the Texas Panhandle field." That pressure is referred to on page 7 of the annual report on the Panhandle oil and gas field, July, 1938. I am the V. E. Cottingham whose name appears on that report, and that report was prepared under my direction. At that time I was director of production for the Railroad Commission of Texas. You will note the report was written by T. G. Post, F. M. Blair and K. I. Dunn, as appears on the first page. Mr. Post did most of the compilation and the writing of this report. He was in charge of the engineering of the Panhandle field. He is a graduate petroleum engineer from Texas A. & M. College, and is now in my employ as a petroleum engineer, doing petroleum engineering at some West Texas field.

You have referred to page 7 of that report and asked me to state just how the weighted average pressure of 337.66 pounds was arrived at by my department under my direction.

Just before leaving Texas I went over the entire report so as to refresh my memory as to the contents with Mr. Post, and I asked him to tell me just how he arrived at the weighted average of the Texas Panhandle field, and

this report I have in my hand is Mr. Post's explanation of it. I understand it that way, but I wanted to be sure because I thought it would come up that there would be more than one way of weighting, and this is his notation on my report. This is my judgment, but I am telling you how I checked myself, because a great deal of the report came through my hands while I was with the Texas Railroad Commission.

I went over this report thoroughly at the time it was prepared, and this weighted average for the Texas Panhandle field was arrived at in the following manner: It is the arithmetical average of pressure on all wells in each zone, multiplied by the total acres in each zone, and then the sum of the acre pounds of all zones is divided by the total acres in the field, which gives the weighted average pressure for the field. The weighted average pressures shown in all of these tables in that report as of July, 1938, was calculated that way for the East field, for the West sweet and the West sour, and for the total field as a whole.

When I spoke of each zone, I referred to the Railroad Commission's pressure map of 1938, a copy of which is before us as Exhibit 12. A small copy of that map is incorporated in the report. The pressure map was pre-
114 pared prior to the report. The reference to the zones in the notation on page 11 of the report was to the colored bands on that map.

The factors considered in that weighting were the average or arithmetical average pressures of the wells in each zone multiplied by the acres. It is the average pressure of the well multiplied by the acres. This gives the acre pounds, and I added those products all together and divided by the total number of acres in the field to get the weighted average pressure. I gave no consideration to potentials or to sand thickness or to anything else except pressure and area.

These pressure maps were not made for the purpose of estimating reserves, but were made primarily for the purpose of prorating gas under the statutes of Texas, more specifically called House Bill 266 and Senate Bill 407. They are different statutes.

Cross-Examination by Mr. Staff.

One of the most important cases in which I have testified was State of Texas vs. Texoma and Consolidated. The

Railroad Commission, pursuant to House Bill 266, promulgated and adopted an order to prorate gas in the Panhandle field, and suit was against the enforcement of the Railroad Commission's order. I testified on behalf of the State of Texas. This proceeding took place in January, 1936. I do not have a copy of my testimony. A copy of it would be available in the abstract of the record in the United States Supreme Court. The case is reported in 300 U. S. 55, 81 L. E. 510. The lower court's decision is in 14 Fed. Supp. 318. In that case I testified on the subject of geology, water conditions, gas-oil ratios, and the effect of the formula as applied to these companies. I did not testify with respect to reserves. I don't believe that subject came up. The State was represented by the assistance of the Attorney General.

Another case in which I testified was the Henderson case, touching on this particular field again. I believe it was tried in 1938. That was another proration case. They attacked the Commission's order prorating sour gas. That order, however, was promulgated under the authority of Senate Bill 407 and that case was tried before a three-judge court in Austin, Texas, and they sustained the Commission's order. It was the first proration that has been sustained in the courts. The title of that case was Railroad Commission of Texas vs. F. C. Henderson, and it is reported in the official reports. My testimony was with reference to drainage, water problems and geology. I was the only technical witness representing the State in that particular suit. No appeal was taken in that case.

The last important case in which I appeared was a case styled Rowan & Nichols vs. Railroad Commission of Texas. It was a suit attacking the proration formula obtaining in the Texas oil field. That case was heard during the first week of February, and the decision has not been handed down. It was before one Federal judge in February, 1939.

It was a suit against the State in which the Attorney
115 General represented the State.

There are other cases where I testified in some of the District Courts at Austin involving spacing rules. Generally the testimony hinges around the drainage of a well. Of course, I appeared each month before the Railroad Commission. The statute requires the Commission to hold a hearing each month with reference to gas and oil statutes, and I appeared before the Commission each time,

giving more particularly information with reference to the Panhandle field and to the East Texas field.

I do not remember offhand the names of the different cases in the District Court. At the time proration first became a function of the State I appeared in the courts at Tyler and Longview quite a number of times; but I couldn't tell you the names of those cases. They concerned violations of the Commission's order with reference to the production of oil surreptitiously.

I have not appeared before the Texas Legislature or any committee of the Texas Legislature within the last five years, or submitted any reports to the Texas Legislature or to any of its committees. This is the first time I have testified since leaving the Railroad Commission.

Redirect Examination by Mr. Morgan.

I have never appeared as a witness for Texoma Natural Gas Company or Natural Gas Pipeline Company of America before today. I have never appeared as a witness for any client represented by counsel or his firm until today. I have always been on the opposite side of the table.

(At this point appears the following discussion:)

(Mr. Booth: I think we ought to have an understanding with Mr. Morgan on this point: The Commission ruled that you were to proceed first with the presentation of your testimony at the initial hearing and you declined for various reasons to proceed. You have now called Mr. Cottingham and you are proceeding with other witnesses. Do I understand that you are now presenting the testimony by these geologists as the beginning of the presentation of your entire case in defense of your present rates?)

(Mr. Morgan: I had not stopped to think about it. I have had so much else to think about, but it is our purpose to put on our geological testimony covering the ground covered by Mr. Brown's testimony on direct and at that time I will know, when I have completed this stage of the case, whether I am going to have some more testimony. The Examiner can see by this time that this is no merry pastime, getting ready to put on testimony of this character, and I have no objection to counsel for the Commission and for the Illinois Commerce Commission putting on proof in the meantime, or I can put on mine following this geological testimony, just as rapidly as I can get it ready.)

(Examiner Simpson: I think the time to raise that

question, Mr. Booth, is after the time the testimony has proceeded just a little bit farther.)

(Mr. Booth: But I thought it might be helpful in working out our future plans in reference to the case if we knew Mr. Morgan's intention, and I think his statement clears it up, and the only question that comes up next week, then, will be the amount of time that he will request to present the remainder of his case.)

116 C. J. PETERSON, a witness for defendants, testified as follows:

Direct Examination by Mr. Morgan.

(May 26, 1939)

My name is C. J. Peterson. I am a resident of Amarillo, Texas. I was born in the Hawaiian Islands in 1885. I received my high school education in the Islands, and took the degree of Bachelor of Arts in the Department of Geology and Mining at Leland Stanford University, in 1910. My studies at Stanford University were entirely geological and engineering as relating to mining, specializing in economic applications of geology.

Since leaving Stanford University in 1910 my entire career has been devoted to economic work in the application of geology. In 1910 I took a position with the Tonopah Mining Company of Nevada as assistant mining engineer. During that time my duties were ground surveying, sampling of ore bodies, estimation of reserve of ore bodies, and reports of examinations on mining properties. I continued with that company until 1912, and later went back to work for them.

In 1912 I went down to Venezuela as geologist for the New York and Bermudez Company, which was a subsidiary of the Barber Asphalt Company. At that time the Barber Asphalt Company and its subsidiaries had concessions of approximately five-sevenths of the whole of Venezuela for oil exploration purposes. However, they had to make a choice of the best part of that territory within a certain time limit, and my duties in Venezuela consisted, with a number of other geologists, in segregating from the concessions held by the company the properties which were of greatest value for oil or gas exploration.

Returning from Venezuela I again went to work for the Tonopah Mining Company of Nevada. I stayed in Venezuela about one year. This time the Tonopah Mining Company employed me as an examining mining engineer in exploration work for the company. This work embraced examinations of mining properties in practically all of the mining states of the United States, and also in Nicaraugua. After my work in Nicaraugua I returned to Tonopah and was for a year their acting chief engineer for the company in charge of all its mining operations,

In 1917 I took a position with the Empire Gas & Fuel Company as petroleum geologist, with my work mainly confined to surface geology in the Osage field, Oklahoma. I left their employ in 1917 to go with a company which was known as the Hamilton Oil Corporation. This company did geological exploration work in several states, and while in their employ I had to make examinations of and purchases for them of properties in Oklahoma, Texas, Kansas and Kentucky. My work then embraced surface and
117 sub-surface geology, estimates of oil and gas reserves, and detailed surface examinations of properties.

In 1921 this company sold out their properties to what is now Continental Oil Company, and for a year I worked as a consulting geologist in Tulsa, Oklahoma, in association with Mr. C. L. Severing.

In 1923 I again went to work for the Empire Gas & Fuel Company, this time as a petroleum geologist for that company in the Rocky Mountain Division, with offices at Denver, Colorado. During my work for what was called the Rocky Mountain Division I had to make surface geological examinations and determinations of the value of properties in the States of Colorado, Utah, New Mexico, Wyoming and California.

At the end of 1926, I left the Rocky Mountain Division and took a position at the head offices of the Empire at Bartlesville, Oklahoma, as geologist in charge of exploration work for the Cities Service Gas Company. My work for this company embraced sub-surface geological work, geological work involved in estimating gas reserves, and was largely connected with the determination and recommendation to the company of pipeline projects. In other words, when it became apparent that gas was occurring in certain sections of the state, it was part of my work to tell the company whether or not gas pipelines were justified to those places. This, of course, involved estimates of what reserves

might be available and whether or not these pipeline projects would be economical.

In the course of my work in this connection, the Cities Service Gas Company built its gas pipeline from the Panhandle field to Wichita and from there to Kansas City, which now furnishes Kansas City with some of its gas. Also in my work with the Cities Service Gas Company, through a study of the geological conditions in certain abandoned fields owned by that company, I instituted a storage of gas in these abandoned gas fields and these gas storage projects are now working on a commercial basis. They had certain gas fields which had been abandoned, that were near the market of the Cities Service and they took the gas during the summer, when they haven't a peak load on their line, and stored it in the old gas fields, and when the winter peak load is on they have this storage to draw on when they have a peak load.

This pipeline out of the Panhandle to Wichita and then to Kansas City was built in 1928. I did some work in the Panhandle prior to the building of that pipeline. Before any recommendation could be made for a pipeline out of the Panhandle field, it was necessary to estimate the reserves in the field to determine whether or not such a line was justified. That was my work. It was work in connection with that that enabled me to recommend the building of this pipeline. That was the pipeline extending from their main compressor station near Pampa, in Gray County, situated at the point I indicate on Exhibit 13, in a northeasterly direction through Roberts and Hemphill Counties. It gets its gas for that line from leases situated in the western part of Gray County and scattered leases in the eastern part of Carson County, and from an immense lease which cov-
118 ers the greater portion of what is known as the Burnett ranch, involving an area over ten miles square, just west of the central portion of Carson County.

I continued to work for the Cities Service Gas Company until 1930, when I took a position as chief geologist for the Continental Construction Corporation which initiated the organization of Texoma Natural Gas Company and Natural Gas Pipeline Company of America. My duties were confined entirely to studies in the Panhandle gas field. These studies had to do with preliminary work which was used in the organization of Texoma Natural Gas Company and Natural Gas Pipeline Company of America. It was in August, 1930, that I began my work with Continental Construction

Corporation, and since that time I have devoted my entire time to the study of geological and production conditions in the Panhandle field.

I have an organization under my direction as chief geologist of Texoma Natural Gas Company. That organization, known as the geological department, consists of a stenographer, a draftsman, a man who is employed to collect, wash, dry and file samples of well cuttings from the wells in the field. These cuttings are filed in detail so that we can pick out any footage in a well and tell just what occurred at that footage in the well in the way of formation. They are samples of cuttings made when the wells are drilled, and from these samples I can tell at any point what was encountered in the well when it was drilled. I also have an assistant, a graduate geologist, Mr. W. F. Brainard. He is a graduate of Syracuse University in the department of geology. He took his Master of Science degree in that university in 1922. He has been employed in economic geological work ever since 1922. His duties are as assistant to me and we work together a great deal of the time. He is very experienced in microscopic work in the examination of samples and he has done a great deal of that work under my direction. We work together on that but he is perfectly able and competent to do it by himself.

This microscopic work involves equipment like microscopes etc. and we have some of the best microscopic equipment which is known, consisting of a Spencer microscope with special lenses, special lighting equipment to light the stage. This microscope was made especially for the examination of well cuttings. We have examined with the microscope well cuttings from 591 wells in the Panhandle field. In the course of doing this we examined 12,830 samples, and have on file in our office for reference over 60,000 samples of well cuttings from the Panhandle field.

In the preliminary work in the field we used to take well cuttings from the ground all the way down to the depths of the wells, because it was necessary to find out exactly what the conditions were in all formations, and we did not wish to overlook any possibilities in the upper formations. As a result of our experience in examining the wells located in different portions of the field, we are now able to narrow our examinations to just certain portions of the formations in certain portions of the field. For example, in the portion of the field where Texoma Natural Gas Company is drilling its wells, our examinations begin at about a point

slightly above the top of what has been called the Big Lime. This is the top of the anhydrite section.

119 On Exhibit 16 the top of the big lime is shown by a heavy dark line beginning at the figure "1000" and going irregularly across to the words "Top of the Big Lime." That big lime, however, is not confined to the area presented by this cross section. It occurs all over the field in the same relative position with reference to other layers. The only difference is that in some places it is a great deal thinner than is shown in that cross section.

I have had something to do with the drilling of Texoma's wells. My duties for Texoma involved choosing the best locations for the drilling of wells, the determination of the points at which casing must be set in these wells, the determination of what depth these wells shall be drilled to, and also it is part of my duty to determine the relative value, geologically, of acreage owned by Texoma, to determine whether or not the company shall drill on leases or shall acquire leases. In this connection my work is limited entirely to determining whether or not a lease should be bought or sold or drilled. I have nothing to do with the commercial values of these leases. That is determined by the economic part of the company—what price they shall pay for these leases or sell them for. I pass on the prospective production of the lease—whether I think it is advisable for Texoma to drill or to acquire it.

I have a record on each well we drill of the formations through which the driller passes as he goes down from the surface to the producing formation. The record, which is kept by the driller, is called a log of the well. This log shows the formations encountered in the well, the depths at which they are encountered, the shows of oil or gas which are encountered in the well, and the depths at which they are encountered.

I have personally spent a great deal of time in studying conditions during the drilling of Texoma's wells. As a matter of fact, I have many a time gone out to a well and stayed on the derrick floor for periods ranging from 18 hours to 36 hours, and in one case even 72 hours, without any sleep, so as to get actual information regarding the formations encountered, the way they were encountered in the well, the way that gas was encountered in the well, the actual thickness of the formation containing the gas, and how it acted when it was encountered. I have personally during

the drilling in of a well gauged that well during its drilling in at five foot intervals, to find out just where the gas was.

One of the methods of determining the thickness of pay is to drill in the gas and take a gauge of it, take another gauge after it is drilled a few feet more, and if the gas has decreased in volume we will drill another five feet beyond to find out if there is any gas in that part of the formation; and if we get an increase in gas we will know that in that way we found out exactly how thick the gas formation is.

All of the logs of Texoma's wells are on file in my office. I have in my office probably over 3000 logs on file of wells in the Panhandle field. I continually study these logs in connection with my duties, and have studied them over 120 the past nine years. They are my Bible down there.

They are logs from other wells drilled over the field. They are all the logs which are available to me and such as I can get for my study. I study every known log. I watch the logs of new wells as they come in, in order to keep abreast of the conditions as they are revealed by new wells drilled from time to time. I go out and watch them drill some of the time. I watch wells drilled by other companies and always make arrangements to obtain samples from them for my collection so I can tell what formation they went through, what they encountered in their wells. In that way we can get an idea of what the conditions are outside of Texoma's own acreage. That is the only way we can keep informed—by a study of wells being drilled outside of our own acreage. That gives us an idea of the chances we have to run.

Texoma has at this time approximately 159 wells. I say approximately because we are in the process of drilling a number of them and I can't state the exact number now because some may have been completed since I have been up here in Chicago. I am just talking about the number of wells we now own. We have had to abandon seven wells.

Going back to the period prior to 1928 when I was making an investigation down in the Panhandle on which I made reports concerning the advisability of building a pipeline from that field to Wichita and Kansas City by the Cities Service Gas Company the field was not at that time known to cover the same terirtory it is now known to cover. The development at that time was considerably restricted as compared with what the development is now. The borders of the field could not be outlined as they can today through the use of wells which have been drilled. In 1928 most of

the production had been along the northeast flank of the field and mainly consisted of wells which were drilled for oil. As a matter of fact, many of the wells encountering gas were drilled with the idea of encountering oil. Very few wells had been drilled prior to that time for the definite purpose of producing gas. Most of them drilled prior to 1928 were drilled with the intention of encountering oil. They got off the clearings as far as oil was concerned and brought in gas wells but no oil. By that means it became known that there was a large quantity of gas in that field, but they kept drilling for oil and kept getting gas instead. They were very disgusted with it, for they were after oil.

Going to Exhibit 13, I will point out on that exhibit where the oil fields in 1928 were. The main producing pool, at that time was near the town of Borger, known as the Borger field, which is in the southeast part of Hutchinson County. It is a little hard for me to remember that far back as to where the oil pools were; but they had some oil at that time out near Pampa, in western Gray County, and they had done some drilling in the Lefors area. That is another town in the central part of Gray County.

Having found by the development to that time that there was oil in that country, the bold, who were willing to speculate with their money, had drilled a good many wells scattered out all over that country in search of oil; and in the doing of that they had discovered these gas for-
121 mations demonstrating that a great gas field lay there. The real big oil development started in 1926.

I did not know at that time how far west and how far south the gas field extended. We did not know how far west, how far northwest, how far south or how far southwest that field extended until we obtained our present information, which was in 1937. We haven't been able to change any of our ideas of the boundaries of the field since 1937; but down to that time the boundaries were being changed by outlying developments, finding wells where it was not known before that wells could be found. The present contours of the field have not been as they are now until 1937. We think we have a pretty good idea of the limits of the field now. It may be changed at any time. It might extend a little further than we have it outlined. It is very hard to tell just what you are going to get in a well drilled on the edge of the field; but we are pretty certain that the edges of the field are defined now on account of our structural conditions. The structural conditions show that we

have about reached the limits. The producing formations as we go around the perimeter of the field are dipped down approximately to sea level. As we are able to project the depth, as shown in the wells, it is about to dip into water at the limits as we now have the field defined.

Since 1937 a slight change has been made in the perimeter of the field by the Texas Railroad Commission; but I did not adopt that change. The main change they made was in the border of the field which is shown in the central part of Carson County—a comparatively short line in a northwesterly direction to the central part of Carson County as shown on Exhibit 13. They moved it slightly to the southwest because they had a couple of wells located incorrectly on their maps. These wells were wells which occurred in Block 5, B & B, which is in the west portion of Carson County. They thought they were in Block 5, I & G N, near that boundary of the field which we were just discussing. From that they drew their line on account of these incorrectly located wells. They are now aware of the fact and admit that those wells were incorrectly located. In other words, they put the wells on the same section numbers in Block 5, I & G N, that had actually been drilled in Block 5, B & B, and that got them out of the border of the field as it then existed, so they just dropped their line further over. They thought they had a development which warranted changing the borders which had not occurred. I have pointed that out to them and they admit there is no reason for changing the border of the field there.

My conception of the field is the same as it was portrayed on the Railroad Commission map of 1937. I think it was one of the best jobs that was ever done in outlining the field. That map is Exhibit 17, as is my present conception of the boundaries of that field.

The change was really not a major change. You can hardly detect the difference between it and the line I have used on Exhibit 17. They had a couple of wells which they thought were located approximately in the center of Carson County, near the "S" in "Carson" as shown on Ex-
122 hibit 13. They thought those wells were there and they moved this line slightly down and increased the area of the field slightly. It was not major and did not affect the area very much, because the change was compensated for, but I wanted to draw attention to the reason why I am defining the border as I am over there. My Exhibit 17 keeps the line in the old place.

That is a part of the difference in acreage that Mr. Brown pointed out in his testimony, but another reason for the difference is that I have used a different method of measuring my acreage. My acreage has been estimated by taking each section, section by section, and checking the number of acres involved. The Railroad Commission's estimate of acreage was obtained by the use of the planimeter.

At the time I was first engaged in the study of gas reserves and prospective productivity in the Panhandle, back in 1928, it was known that there was some sour gas there and there was a tentative location of part of that line. The development at that time did not show just where the line was located throughout the whole field. There had been some sour gas wells and some sweet gas wells drilled then in the search for oil; but they had not drilled enough in the vicinity of that line so that its location was definitely known. There was not enough development on the border between the sour and sweet gas to determine just where the sour gas was located.

There was not sufficient information in 1930 and 1931 to definitely locate that line on the ground. Practically all the information about the line in 1931 was about its existence in Western Gray County and northeastern Carson County and southwestern Hutchinson County. There were one or two sour gas wells in Moore County at that time, but nothing could be told then as to where the line was. There had not been enough drilling to locate it. Our impression at the time from the one or two gas wells we had was that they were freaks. We didn't think it meant anything. In 1931, we did not know that the sour gas line was in the position in which it is now shown on Exhibit 13.

(EXHIBIT NO. 19 for identification, offered and received in evidence without objection.)

I have already stated that in 1928 and on down to 1931, wells had been drilled and were being drilled in search of oil, and that in many instances those wells did not produce oil but disclosed the presence of gas.

Prior to 1928, there was a small local pipeline going to Amarillo, Texas, from Potter County, but there were no large pipelines going out of the field at that time.

The wells which had been drilled into gas down to 1931 did not make the same quantity of gas per well. There was a big variation in the open flow potentials. The wells ranged from one million to one hundred twenty-five millions. From the fact that we had one million cubic foot wells and 125

million cubic foot wells in different parts of the field, I drew the conclusion that there was an immense variation in acre content and reserves underlying the different
123 portions of the field; but I did not know in 1931 the production of the field would turn out to be, as I do in 1939. There was then no way of being certain about that. An immense number of wells have been drilled since 1931 in search of oil and also in the development of gas.

In December, 1938, there were 4032 producing oil wells and over 1500 producing gas wells. That does not include all the wells which have been drilled. It includes only the wells that are now producing oil or gas. A great many wells have been abandoned in the field, especially in the oil fields, and a considerable number of gas wells have also been abandoned.

(Map entitled "Rock Pressure Map, Texas Panhandle, 1932", marked Exhibit No. 21 for identification. Map entitled "Rock Pressure Map, Texas Panhandle, 1935", marked Exhibit No. 22 for identification. Map entitled "Rock Pressure Map, Texas Panhandle, 1937", marked Exhibit No. 23 for identification.)

Exhibit 21 is now presented to me. It is marked "Rock Pressure Map, Texas Panhandle, 1932". I contoured the map and the exhibit was made under my direction in 1932. It purports to show by contours at 20 pound intervals the rock pressure conditions existing in the Texas Panhandle field in 1932. The different 20 pound contour intervals are designated by different colored bands with the exception of the contours which would reach above 400 pounds. On the exhibit, the area which had a rock pressure above 400 pounds, is colored yellow. Also on the exhibit the area in which the rock pressure was below 200 pounds is colored gray. The intermediate bands between the gray, representing pressures below 200 pounds, and the yellow, representing pressures above 400 pounds, represent areas in which the rock pressure is divided into 20 pound intervals.

This map also purports to represent the outside boundaries of the field as it was conceived in 1932. There has been considerable change in the boundaries of the field since 1932. Changes have been made in almost every portion except along the northeast as development has progressed, and some changes have been made even along that line. Nearly all of the lines have been changed as between 1932 and 1938. Exhibit 17, the 1938 map, represents my pres-

en conception of where the boundaries of the field actually lie.

On Exhibit 21, a large uncolored area is shown near the center of Gray County, surrounded by heavy dark lines. The significance of that area is that because of dry holes having been drilled there it has become evident that the area has no content of gas or oil in it, for which reason it is regarded as one devoid of productivity. We had to change our conception of that area as time went on, just as we changed our conceptions of the field. In other words, as more dry holes have been drilled, there has been a change of the boundary of that area.

I have stated that in 1926 important oil production took place in the Panhandle. In 1932 the production was largely localized along the northeast part of the field, but still in practically the same position as formerly, only that there was more of it. Prior to 1932 very little gas had been produced for pipeline purposes from the field, and there was practically no restraint of the wastage of gas in the drilling of oil wells prior to that time. There was an immense wastage of gas along the northeast flank of the field by wells which were being drilled for oil. It was wasted
by drilling through the gas formations down to the oil
124 producing formations, allowing the wells to blow wide
open while they were drilling through the oil portion of the formations. It was also used for flowing oil wells. They would use the gas in the upper formations for flowing oil and then let it escape to the air. A lot of gas at that time—really, it was free dry gas—was used by the gasoline plants. They would bring in wells drilled for oil and they would have gas in the upper formations above the oil formations and they would produce this gas with the oil and call it casinghead gas, but the term casinghead gas has been very loosely used in the Panhandle field. There has been no technical reason for it—just the fact that the gas came out of a casinghead made it constitute casinghead gas. This gas had no relation to the gas that was originally in absorption in the oil. Most of the gas that has been used in the gasoline plants in the Panhandle and referred to by the term "casinghead gas" has just been dry gas used in those plants.

A lot of it was wasted in other ways. It was used in casinghead plants and carbon black plants, and wells were left to run open for weeks at a time. I was down there in 1928 and I can remember especially seeing one well drilled

on the Burnett ranch which was a 79 million well. They had a little trouble getting the gate valve shut off, and it ran wide open for three weeks—79 million cubic feet of gas running into the air, every day. The approximate location of that well was Section 79, Block 4, in the northern part of Carson County.

Where oil was developed in a well back in those days, or at the present time the casing is generally set just above the oil pay, which would be about the lower part of the gas bearing formation, as the gas comes right on top of the oil. In the earlier days of the field a great many of the wells there had the casing set without being cemented, and the casing was in many instances raised, which allowed the gas to come down the sides of the casing and go into and be produced with the oil, and in other places it was reported that the casing was ripped. Slots were made in the casing by ripping, which allowed the gas to enter into the well hole and facilitate the production of oil; that is, the gas would be produced with the oil. This is what they all call casinghead gas.

The greater part of the gas which has been called casinghead gas in the Panhandle was, prior to its production, located in the dry gas area—approximately all of it. A negligible quantity, so small that it is commerciaclly of no value to any pipeline or even to a lot of the gasoline plants down there, has come out of absorption in the oil. They couldn't even connect the wells that they have any of that gas in. They don't even take the trouble to connect them up. That is the type of well that the Railroad Commission reports as having no oil-gas ratio. Some of them that have a slight oil-gas ratio are not connected to gasoline plants because there isn't even enough gas to warrant it.

I make the statement that all the gas that has been termed casinghead gas has come out of gas bearing parts of the formation because I have seen wells drilled in and have seen that gas coming into the wells and coming out with oil in a great many instances. I have said "practically all";

there is some real casinghead gas in the Panhandle
125 field. I am not saying there isn't some. I say that it
is a negligible quantity as compared with the total gas that has come out because the proportion is infinitely different. It is a very small quantity in comparison to the total amount of gas that has come out.

I have had occasion to investigate the source of the gas that has been produced over the Panhandle during the nine

or ten years that I have been down there. I have conducted researches and investigations and made observations to determine where that gas is coming from. The result reached by me as a consequence of those researches and investigations is that I consider that the major portion of the gas comes from the gas producing formations. It would have been impossible for that gas which has been produced from oil wells down there to have come out of absorption in the oil. The quantity would be absolutely negligible in comparison with the total amount of gas that has been produced with the oil in the field. In comparison with other fields in the United States, there are very few where there has been such an immense amount of gas that has been produced with oil. It has been out of all reason.

Questions by the Examiner.

Casinghead gas generally comes out as the oil flows and frees itself in a comparatively short time. The point I am trying to make is that the immense amount of gas which has been reported as casinghead gas and as produced with oil in the Panhandle field is not casinghead gas nor gas from absorption. That immense quantity could not possibly come from either of those sources. The only way we can tell that oil has a certain amount of absorbed gas would be by analyses of oil, such as has been submitted in this hearing by other witnesses. When gas is absorbed by oil you will not be able to detect it with your eye. It is a subject for analysis.

Direct Examination Resumed by Mr. Morgan.

If the gas is absorbed, it has become a part of the liquid. It may escape as the pressure goes down. Some of the gas might come out of the oil as the pressure was reduced, which would allow this liquid to turn into a gas.

It has not been an uncommon thing in the Panhandle field to find a well producing ten million cubic feet of gas and one barrel of oil. I do not think there is a chance in the world that ten million cubic feet of gas have been absorbed in a barrel of oil. That is the point I am trying to make.

The wastage of gas in the Panhandle field did not cease when the pipelines were built into the field. As a matter of

fact, shortly after the major number of pipelines were built in the field some of the greatest wastage of gas occurred in the Panhandle field. This waste of gas occurred mainly in 1935, as I remember. At that time legislation allowed the use of dry gas by gasoline plants for the production of gasoline and permitted these gasoline plants to pop the residue into the air, and since the dry gas had a very small gasoline content of about three-tenths of a gallon per thousand cubic feet, the gasoline plants, in order to make a large amount of gasoline, had to use immense quanti-
126 ties of gas, and since they were not restricted in the usage to which they put their residue they just popped this gas into the air. The result was that at one time there in 1935 they were popping into the air one billion cubic feet of gas a day. That gas was being produced largely along the northeast flank of the field, just off and in the oil producing part of the field.

I have a map or graph in which I have portrayed the production of gas from the Texas Panhandle field by years. The figures used in that graph for the years prior to 1932 were obtained from records published by Victor Cotner and H. E. Crum, published and presented before the American Association of Petroleum Geologists at an Oklahoma City meeting in 1933. Those men had lived and studied in the Panhandle gas field practically since the beginning of the field. At the time, prior to 1932, when they were present in the field, the Railroad Commission did not issue reports on the production from gasoline plants. They did issue some pipeline reports; but on a lot of those details of gas they did not keep records. Mr. Cotner was with the Columbian Carbon Company, which was interested in gasoline production from gasoline plants, and these men were in position to obtain actual information on the gas which was being used by these plants which was nowhere else obtainable, and they kept careful records, and their reports of production have been generally accepted as the best records that can be obtained on the production of gas in that period.

They worked in collaboration with other geologists and production engineers in the field in compiling that original estimate of gas produced as of the time they made it. They not only took their own figures, but they were in continual contact with everybody from whom they could get such information, just as when they wrote their report they got all the geologists down in the Panhandle field, practically, to

aid them with their information. This estimate of reserves by Cotner and Crum was a published scientific paper, based on very extensive researches, and is the generally accepted authoritative estimate of reserves as of the time it was published. It is accepted by the fraternity of geologists and members of the American Association of Petroleum Geologists as an authoritative document, and the Railroad Commission of Texas, in all of our legal contentions with it, has never questioned it in any way.

At the present time, the Railroad Commission keeps a record of the production of gas wells, and in addition to those two sources, the Railroad Commission reports and the Cotner and Crum publication, I have from 1932 on used records that are available from the Railroad Commission of Texas on the withdrawals of gas, such as those by the gas pipeline companies and the gasoline plants. In addition to that, there is quite an amount of gas the production of which is recorded nowhere and which has to be estimated. There is the gas, for instance, which is used for fuel in drilling wells, the gas which escaped from unconnected oil wells, the gas which escapes while oil wells are being drilled in, and the gas which escape while gas wells are being drilled in. With the aid of information obtained from the scouts of the different oil and gas companies in Amarillo, I have made estimates of the gas which has been used in these ways. This information consists of actual reports on the wells which are drilling, the amount of time they are drilling, and the amount of gas which they encounter as they drill. With the aid of this information, by figuring the actual well days during which the gas is
127 being used for fuel or is escaping from wells or is being wasted in the drilling of wells, I made my computations. I go to an immense amount of detail in that matter. It is the best estimate I know to make. It is an important part of the gas. It isn't a big amount, but it does have an importance.

I have made it a part of my duty to my employer to keep abreast of the production of gas in that field throughout the period I have been down there as chief geologist. It is a very important matter to us to know the amount of gas that is being produced from the field.

(Graph entitled "Total Gas Produced From Texas Panhandle Oil and Gas Field Shown by Daily Averages, 16.4 lb. Base," marked Exhibit No. 24 for identification.)

I collected the information for the graph marked Exhibit

24 for identification and had it made under my direction. I explain the graph by pointing out that the blue coloring at the bottom represents the gas used by gas pipelines in daily averages. It shows the daily average throughout the year for each separate year. The brown area above the blue portrays the total gas used by gasoline plants, in the aggregate. There is some cross-hatching in the lower portions of the brown columns. That portrays the residue gas used for carbon black by the gasoline plants. That part of the brown area not hatched represents the gas used by gasoline plants where some of the residue is blown to the air, some used for plants on the lease, and some for the operation of the gasoline plants. For the period between 1927 and 1935 a great proportion of the residue was blown to the air.

The green color represents gas blown in the air and used for fuel in drilling wells. It includes gas used for fuel in drilling oil and gas well and gas blown to the air, not from gasoline plants, but during the drilling of those wells.

The red represents casinghead gas not treated but which was allowed to escape from oil wells not connected to gasoline plants.

In 1926, there is a small coloring in blue and a comparatively small coloring in brown. That is accounted for by the fact that during the inception of the usage of gas in the Panhandle field neither the gasoline plants nor the gas pipeline production had been initiated in any great amount. The only pipelines in the Panhandle using gas for pipeline purposes in 1926 were local lines like the one to Amarillo and pipelines to other little towns around the field or in the field. In that year, which was the first year of oil production in any substantial quantity, the casinghead gasoline plants were just being introduced.

By the next year, the pipelines were still confined entirely to local consumption; but the gasoline plants had begun to get in their work, and the column jumps up, as indicated by the daily averages in millions of cubic feet shown on the chart. We find the pipelines probably had about ten million a day during 1926 and slightly more than that in 1927, whereas the gasoline plant use had jumped 128 from approximately 100 million a day in 1926 to approximately 740 million in 1927.

In 1928 there is a perceptible change in the blue coloring, due to the starting of production of gas by the Cities

Service gas pipeline that was built in that year. The Denver line was also completed in that year. Gasoline plant consumption continued to go up until it had reached a substantially higher figure in 1928.

The total production of gas for all these purposes during 1926 was approximately 655 million cubic feet per day. In one year the production jumped up to 1,390 million per day; and the next year the daily average figure was 1,480 million. In 1929 the total figure had reached 1,700 million. In 1930 it was 1,690 million. In 1931 it was 1,380 million. In 1932 it went down to a little over 1,140 million cubic feet per day.

The occasion for the gasoline plant use going down during that period was partly because of a lack of demand for gasoline, the industrial conditions, and the price of carbon black; but there was also a tightening up by the Railroad Commission in the matter of the wastage of gas and the abuse of the use of dry gas in gasoline plant operations. Mr. R. D. Parker was in charge of oil and gas regulation enforcement for the Railroad Commission during the years 1930, 1931 and 1932. Mr. Cottingham came after Mr. Parker.

In 1933 the production jumped up again. There was a slight increase in the production of pipeline gas, but a larger increase in the use of gas for other purposes. The occasion for that increase was that in 1933 the Railroad Commission began to loosen up its restrictions and allowed a greater production of gas wastefully. Special permits were issued permitting the use of dry gas for the manufacture of gasoline, allowing the residue to be popped off in the air. That resulted in an increase in the number of gasoline plants in the field, beginning in 1933 when those permits were issued. By 1934 a number of new casinghead plants had been completed and the State of Texas allowed them to use dry gas for gasoline and pop the residue to the air, and the production shown for the years 1934 and 1935 resulted. The total production for 1934 was about two billion one hundred million cubic feet per day, and in 1935 it had gone on up to 2,110,000,000 cubic feet per day.

In 1936, through litigation, the State of Texas was prevented from allowing the use of dry gas for production of gasoline where the residue was allowed to be popped to the air. That reduced the total production of gas in the year 1936 by some 600 million cubic feet per day.

In 1937 the usage of gas increased. The pipeline gas

increased and has been steadily increasing right along. In 1937 the total amount of gas produced amounted to 1,610,000,000 cubic feet per day. There was an increase in the production of carbon black, or gas used in the manufacture of carbon black, in 1937 as compared with 1936.

In 1938 the carbon black production fell off some-
129 what because of a decrease in the price of carbon black and an over-supply for the market at that particular time. The use of gas by the pipelines fell off somewhat in 1938, due to a decrease in the use for industrial purposes. I think this falling off in the production of gas for both carbon black use and pipelines use in 1938 as compared with 1937 was due entirely to the difference in business conditions, because so far as the usage of gas is concerned in the Panhandle field, the wastage is being very well controlled and the falling off is not due to control in the field, but to outside business conditions causing a smaller use of gas.

This graph shows that the general trend has been for the gas used by gas pipelines to increase in amount as the years go by. The last of the large pipelines out of the Panhandle field was completed in 1931. All of the lines now taking gas out of that field have been there since that year; but they did not take as much gas in 1932 as they did in 1933, or in 1933 as they did in 1934, and they did not take as much any year after that time as was taken the following year until we get down to 1938. The pipelines now taking gas out of the field are not taking all the gas they are capable of taking.

The trend of the usage of natural gas for carbon black purposes during the history of the field to 1938 has been for its use to increase each year, except for one or two years when there has been minor recessions in the use of gas for that purpose. There was a slight falling off in the use for carbon black in 1938. The gas used for carbon black is produced on the northeast flank of the field from the gasoline plants. It is not produced from the plants, but is produced from dry gas wells and the major part of this production comes from the sour gas area of the field. The rest of it comes from gas which is produced with the oil in the oil area. I should say there are approximately 33 of those carbon black plants in the field.

I wish to make an explanation to the Examiner concerning the total quantity of gas that goes to gasoline plants in the Panhandle as shown by Exhibit 24. In the reports

of the Railroad Commission the only gas which they report is the gas used by gasoline plants and the gas used by pipeline companies. Now, as it happens, in the Panhandle field the Northern Natural Gas Company uses residue gas for a part of its load. This gas is reported in the report to the Railroad Commission as gas going to gasoline plants; so in making up my summaries, to keep the usage of gas segregated between gas used by gasoline plants and gas used by pipelines, I subtracted the gas used by the Northern Natural from residue gas from the total gas which is used by gasoline plants and added it to the gas used by gas pipelines, just to keep my total figures correct showing the proper usage of the gas. The correction is used from 1932 through 1938, and involves approximately 40 million cubic feet per day.

The reason I am calling this to your attention is that if you check the records of the Railroad Commission against my chart they won't agree in that respect; because I have had to make this correction in order to get the proper usage of gas separated as it was really used.
130 This volume has not been uniform during the period from 1932 to 1938 but has varied from year to year, starting at a great deal less than that and gradually increasing. I have the figures from year to year and they are readily available.

All of the gas that is carried out by pipelines is included in the blue, even though it goes through a gasoline plant. That is true as to Texoma's gas, which goes through a scrubbing plant. This scrubbing plant is used to scrub the gasoline out so it will go through the pipeline at an economical cost. That is true of nearly all the gas, and the reason I make a distinction in the case of Northern Natural, and perhaps others, is that they buy this gas from gasoline plants instead of producing it and running it through their own plant. There is one other little difference. In the report issued by the Railroad Commission, they report the disposition of residue gas, and in that disposition show gas used for repressuring. The gasoline plants use some of their gas for repressuring. They run it back into the gas wells or into the oil wells, which increases their production. Since this gas goes back into the field, I always subtract it as being gas that has not been produced. I do this to avoid duplication. I consider that as having gone back into the field, so it has been subtracted from the gas used by gasoline plants. That would make a slight dif-

ference between my results and the annual reports of the Texas Railroad Commission because they have not gone into those details.

I have prepared a tabulation of the daily average production of gas in the field during the years to 1938, inclusive, which is portrayed by the graph marked Exhibit 24.

(Document entitled "Gas Produced From Texas Panhandle Field," marked Exhibit No. 25 for identification.)

(EXHIBITS 24 AND 25 for identification, offered and received in evidence without objection.)

I have used this same graph and this same set of figures in litigation with the Texas Railroad Commission. I used the figures from the year 1926 through July, 1935. They have never challenged or questioned those figures in any way. They are the same figures which were adopted by Mr. Brown in his direct testimony, except that they are brought on down to the end of 1938. I have listened to Mr. Brown's testimony and have also read the transcript.

Exhibit 22 was prepared under my direction by my own staff. I did the contouring on it. It portrays by 20 pound interval contours and colored bands the rock pressure conditions in the Texas Panhandle field in 1935. The same legend is used on this map as that used on Exhibit 21. The gray area shown on the northeast flank of the map is the area which has a rock pressure of 200 pounds and less. The colored bands extending on the exhibit in a southwesterly direction across the field show by separate colors, by 20 pounds intervals, from the 200 pound interval up to the 400 pounds interval. The area colored in yellow on the map is the area which is above 400 pounds; that is, which was above 400 pounds in 1935.

This map was made in 1935, using the then existing official pressures as shown by the records of the Railroad Commission.

The 1932 map was based on information obtained by consulting some of the Railroad Commission records in
131 Pampa and from consulting different companies which owned wells in the field. In 1932 the Commission did not issue any report of the rock pressures. I obtained them from actual records of pressure tests, either from the Commission or from the company which owned the wells. I got most of the data from the Commission's files. They had the information but did not issue a report in 1932. As I remember it, they began in 1933 to get out the reports.

It was some time between 1932 and 1935 that they began that practice.

Exhibit 23 was made under my direction. I contoured it. It has the same caption as the other pressure maps except that it is for the year 1937. This exhibit portrays the same conditions, with the same legend as that appearing on Exhibit 22, only this is for the year 1937 instead of 1935, as shown by Exhibit 22. The same pressure bands represent the same pressure on each of the three exhibits, Nos. 21, 22 and 23. The pressures on Exhibit 23 were the prevailing pressures in the year 1937 as shown by the records of the Railroad Commission and appearing in its report. The exhibit was made in 1937.

Exhibit 17 was prepared under my direction in my office in 1938. I did the contouring on it. The same colored bands signify the same pressures on that exhibit as on Exhibits 23, 22 and 21. The same color scheme has been attempted to be used, although the colors are not exactly the same, as I note some of the color is a little darker on this map than on the others; but the same general scheme has been used. When I use yellow, whether it is of the same shade of yellow or not, it portrays the same pressure.

The Railroad Commission in getting out its reports on rock pressures for the Panhandle field usually makes these reports cover the end of either July or August in each year. These maps represent the conditions shown by those Railroad Commission reports, and the date on each map shown in Exhibits 21, 22, 23 and 17 is approximately the end of July of each of the years mentioned. The Railroad Commission causes tests to be made of the pressures and the open flows of all the gas wells in the Panhandle in December of each year, and those tests are incorporated in these reports from which I took the data that is represented by these maps.

These tests generally involve a period of about three months. A test on one well may be made three months before or after the test on another well. They send a force out into the field about June and keep them there until they finish the job. They consider July as about the mean date of the time in which they do the work.

The 1932 map was not predicated upon a report issued by the Commission; but a great deal of the data was obtained at the office of the Commission and was supplemented by information directly from the operators who owned wells in the field. In 1932 the date mentioned was September,

except for Wheeler County. The legend states that
132 the Wheeler County Pressures were taken in December, 1931.

These exhibits all show pictures of the same gas field. The only difference in the figures which are colored on each one of these maps is due to the circumstances which I have already mentioned, that the border line and some of the details, like the extent of this barren area near the center of Gray County, have been changed by information derived from the drilling of additional wells after the first map was made.

You point out for illustration that the barren area shown in Exhibit 21 near the middle of Gray County has a narrow neck of yellow colored area lying between it and the uncolored portion of Gray County lying immediately south of it, while in 1935, three years later, a large part of the six miles immediately south of this barren area is now in color, except that a serrated wedge-shaped area extending almost out to the barren area is not colored. When we get over to 1937 this irregularly wedge-shaped area has disappeared, and the line runs substantially across in almost a straight line, except that there is an area that is uncolored at the top of Sections 160 and 161 and on the south. Counsel suggests that all of those changes in that immediate vicinity have been occasioned by actual drilling operations which have occurred from time to time. That statement is correct. The maps are made up entirely on the basis of what the drilled wells have shown to be the conditions.

Counsel also points to a heavy red line running from north to south through Gray County and cutting this gas field in two right across the barren area of which we have just been talking, in Exhibit 23. That line represents the boundary between what is known as the West Panhandle field and the East Panhandle field as designated by the Railroad Commission. It is also shown on Exhibit 17; but it does not appear on Exhibits 21 and 22 because when those exhibits were made the Commission had not divided the field into two separate fields. That was done sometime between 1935 and 1937. It was just a designation made for proration purposes, like the proration designations for the Panhandle proper, Moore County, and the Osborne area made for the purpose of prorating oil. The field was divided into the East and West Panhandle fields for the purpose of prorating gas at the time when they were going to prorate; but it is all one field, one great common reservoir.

Counsel directs attention to a perceptible difference in the appearance of Exhibits 21 and 22, covering the situations in 1932 and 1935 as to the extent of the colored area, and requests me to state the reason for that difference. The 1935 map shows the effect of a continued production of large amounts of gas in the northeast flank of the Panhandle gas field. This increased production, which has occurred between 1932 and 1935, has resulted in the spreading out of the colored bands on the map and a reduction in size of the yellow area on the map. The yellow area on both these exhibits represents the area in which the rock pressure is above 400 pounds.

In considering these maps it will be noted that the 133 yellow area is considerably less in the 1935 exhibit, No. 22, than it is in the 1932 exhibit, No. 21. Also it will be noted that the rock pressure areas shown in gray occupy considerably more territory in the 1935 exhibit, showing the increase of the low pressure area, which is the result of the intensive production of gas which took place in that field. This can be carried on to the other exhibits. They all show the same process of the effect of production.

The color immediately next to the gray, which is a kind of orange color on all the exhibits, portrays pressures of 200 to 220 pounds. My attention is directed especially to Exhibit 21. It is pointed out to me that Exhibit 21 shows that in 1932 the area of pressure between 200 and 220 pounds was a little ring right around the town of Borger and a little ring around an oil producing area down north of the barren area in Gray County, while in 1935 the orange band has taken a very irregular course substantially north of the Borger oil field and encompassing another little oil field—in fact, coming up nearly to southwestern Hutchinson County and down and across the south line of the county into Carson County; then back up in a northeasterly direction back into Hutchinson County. Then it passes out of the colored area. That does not mean that there has been a row of wells drilled in that orange belt substantially along the course of that orange ribbon which has pulled those pressures down. The production from the gray area has caused an extension of the orange area. It is not alone the production from that orange area, although that has had some effect; but the production from that area alone would not have pulled the band down in that kind of a wriggly worm shape.

Coming down into Wheeler County we find a number of

orange colored bands where the prevailing pressures in 1935 are shown to have been between 200 and 220 pounds. The same explanation applies to the shape and position of those orange bands as applies to those around the Borger pool. Their existence has been caused by production in those areas and in the areas of lower rock pressure.

The predominating influence determining the existence of those rock pressure bands and their shape has been the extremely high gas production in the northeast flank of the whole oil and gas field. The same explanation made as to the orange color would apply to the blue area immediately outside that color. The predominating influence is the high production which has occurred in the northeast flank of the field.

There is no conceivable reason why the wells on each of these bands would account for the change in their location. Of course the wells had some effect, but the maximum effect has come from the production to the northeast. In other words, taking gas from anywhere is going to have effect on the existing physical conditions. It is not physically possible from the standpoint of gas wells away from the oil field in the territory covered by the colored bands in Exhibit 22 to have caused any such depression of pressure conditions as is reflected on that map. If the wells drilled on those bands were the cause of what has happened there,

the bands would be in an entirely different arrange-
134 ment and there would be little local drainage areas around the areas of the bands if the change was caused by production in the bands themselves.

I have stated that the areas colored in yellow on each of the four maps represent the areas which at the time the respective maps were made had pressures in excess of 400 pounds. Those areas of lower than 400 pounds had reached the south part of the field by 1935. The area above 400 pounds in 1935 was entirely in a portion of the south part of the field just east of the county line between Wheeler and Gray Counties and just west of that county line, on the south quarter of the field, and the 400 pound band had almost reached the south border of the field in the eastern part of Carson County. All of this is shown by Exhibit 22.

Upon looking at Exhibit 23 we find that the map for 1937 shows a very extensive reduction in areas in which the rock pressure is above 400 pounds. In the map of 1935 practically the whole of the northern part of Moore County which is within the limits of the field was about 400 pounds,

with the exception of three or four small patches in which the pressure was from 380 to 400 pounds. In the map shown on Exhibit 23, more than half the area in the north portion of Moore County was below 400 pounds rock pressure in 1937, and some of it was at a rock pressure of between 360 and 380 pounds, while in 1935 none of that area had a rock pressure range as low as that. Also on the 1937 map it will be noted that about four miles west of the boundary between Moore County and Hutchinson County a large pink area had developed. This pink area shows a range pressure between 380 and 400 pounds. In the 1935 map there was an immensely smaller amount of pink area. In other words, this pink area in 1937 has progressed more than halfway across Moore County to the west, as compared with its position as shown on Exhibit 22, where it is only a small band about six miles west of the county line between Moore and Hutchinson Counties.

Exhibit 22, showing conditions in 1935, shows that practically the whole of Potter County then had a rock pressure about 400 pounds. Exhibit 23 shows that in 1937 there were patches in Potter County having rock pressures between 380 and 400 pounds, a decrease in rock pressure due to drainage to the northeast.

In Carson County, on Exhibit 22, the area which is above 400 pounds extends northeasterly from the south border of the field some eight or nine miles, while in Exhibit 23, which shows conditions in 1937, there is just a thin triangular portion of Carson County which has a rock pressure above 400 pounds.

In central Carson County the area on the south border of the field in the 1937 map which has a rock pressure above 400 pounds entirely disappears, while in the southeast portion of Carson County and the southwest portion of Gray County a large area shown in Exhibit 22 as having a rock pressure above 400 pounds has become practically cut in half. Less than half of that area in 1937 is above 400 pounds. The gray area in the northeast flank of the field, which is the area in which the rock pressures are below 200 pounds, has increased greatly in Exhibit 23 as compared with Exhibit 22.

In the gray area there are alternating dark gray and light gray bands shown on Exhibits 22 and 23. These bands signify 20 pound pressure contours—that is, the most southern gray band would be from 200 to 180 pounds. The next band would show a pressure interval between 180

and 160 pounds, and so on, as you go into the low pressure areas from the higher pressure areas. In some places it is 100 pounds or less.

The thing that happened in the northeastern part of the field in Moore County which has brought about the change in conditions between 1935 and 1937 was the increased drilling of sour gas wells in that area and the production from them. This drilling took place in 1936 and 1937.

There has been a very substantial change in the situation in the pink area in Gray County. The production of gas in the pink area itself could not have accounted for the spreading of the pink area. There has never been any substantial amount of gas taken from the south part of the field located in the East ½ of Gray County. Just a few wells were drilled over there and very little production was taken.

In the extreme east end of the field there is a triangular region still colored in yellow with all kinds of bands around it. This is an area in which the rock pressure has been maintained mainly because a good portion of that area is of such low porosity and so tight that the gas migrates with great difficulty from that area. What gas is in there is kept there by the low permeability. It can't get out to the areas of lower pressure. That is my interpretation of what has happened there which keeps that pressure up.

My attention is called to a little white spot in the southwest corner of Moore County on Exhibit 23 which did not appear on Exhibits 21 and 22. It was the selection of a well by me that created that area. Texoma drilled a dry hole there following my advice to drill a well. I advised them that they would probably get a gas well there, but they did not. My explanation of that situation is that in the area just west of the blank space shown on the map occur gas wells with not very high productive capacity. In the area east of that occur gas wells. At the time I had this dry hole drilled there was nothing to indicate that the whole area might not be productive between these two portions. After I had drilled a dry hole it was evident that there is an area in there with no productivity, and my geological interpretation of it is that the possibilities are that there is a fault in the area which leaves quite a gap. There are two ways of interpreting that, but that is my interpretation.

Going back to the central part of Gray County where we have a barren area, it is a fact that the northern edge of that white uncolored portion lies along a fault and the area

immediately south of the fault is barren. It is my impression that the same situation has occurred up here in Moore County, only on a smaller scale. It is entirely possible that
that has happened. The other explanation would be
136 that there is a low place structurally in that field, or
that there is a steep dip from the east and from the west.

The size and shape of that area is all supposition. It is certainly logical to expect there would be some area outside the hole of the well which will not have any productivity in it. For that reason it is purely speculative as to the extent of the area which is affected. The barren area in Gray County has dry holes drilled around it which show that it is barren all through.

The well drilled in the dry area I have referred to is just south of the line which I have extended in a southwesterly direction from the southwestern part of Moore County, about half way down the curved line. While we were getting that well in it acted in a peculiar way. It didn't have water where it should have had water. There were things in the formation that prevented production in it, which made me think there was a fault there in close proximity to the well. That well is indicated on the barren area by the usual symbol for a dry hole. I have interpolated from the log readings of that well and the wells around it and reached my conception of how extensive that dip is. There is not enough drilling close to the well to give definite control. It could be a little larger than that, or it could be smaller.

Exhibit 17 was prepared under my direction. I personally worked out the contours. It portrays rock pressure conditions in the Panhandle field as of 1938, using the same legends that I used in Exhibits 21, 22 and 23. The pressure bands are described in the legends at the bottom of the exhibit, and the date of the map is also given at the bottom. This pressure map is on a 20 pound contour interval the same as the other exhibits, and the same color scheme is used. Each well has a rock pressure mark showing what its rock pressure is. Every one of the wells shown on Exhibits 17, 21, 22 and 23 has the rock pressure shown in close proximity to the well.

The pressure bands changed their locations between 1937 and 1938. The change is an increase toward the area of lower rock pressure. The lower pressure bands are increasing to the detriment of the higher pressure bands.

As a matter of fact, all of the belts or bands show increased length by reasons of protrusions to the southwestward, except the yellow band. The yellow band is gradually being eaten out by the low pressure bands.

In the north part of Potter County there are wells showing pressures of 405, 415, 395, 412, 386 and 388. Right near some of those wells, and including two of them, is a foot-shaped pinkish area. That is a local depression area. It is a local depression in pounds per square inch caused by local production from the wells which are in the middle of that area. That spot first showed up in Exhibit 23 for the year 1937. It was not quite so large then and in a little different shape. I think the pipelines that go to Amarillo go to those wells. Some of those wells are the oldest producing wells in the field. Upon further examination I recognize that those are the wells that feed the city of Amarillo in part, and have been doing so since the beginning of 137, taking gas to Amarillo. I am not certain of that date.

If there was no production from the gas producing part of this field to the south and southwest of the eastern flank where I have pointed out there has been tremendous production of gas along with the oil, the same pressure bands would not be reflected as are reflected by these maps progressively from 1932 to 1938. If the pressures had been affected only by production from gas wells and there had been no production on the northeast flank of the field, the drainage areas would have been formed where the production occurred from these gas wells. There would be rock pressure depression areas close to where the gas wells were located similar to the one that was just pointed out on Exhibit 23 in the southwest portion of the field in the northeast quarter of Potter County.

The pink patches, one of the common line between Potter and Moore Counties, another at a point to the southwest of the center of Moore County, and still another to the southeast of the center of Moore County, are local rock pressure depression areas where the production from the wells in those localities had a direct effect on the rock pressure at those localities. If the pressure had been affected only by production from gas wells up through that portion of the field which lies outside the oil producing portions, you would have a series of spots in different colors instead of bands or ribbons such as are shown on these different maps. There would be depression areas along the gas well areas where the pipelines are located,

and the tendency would be, if the production in those areas was great enough, for a series of bands to extend from the edge of the field toward the center of the field. They would emanate from the region of the pipeline production in both directions and would have formed a trough toward the edge of the field and across—a condition with the lower pressures at the bottom of the trough instead of having the low pressure areas along the northeast flank of the field.

(EXHIBITS 17, 21, 22, AND 23 for identification, offered and received in evidence without objection.)

Exhibit 16, labeled "Ideal Cross Section, Portion of Texas Panhandle Field," is now presented to me. I made the original drawing for that exhibit and it was prepared under my direction. In reality, as far as the major part of the exhibit is concerned, it is a typical cross section of that portion of the field, because the exhibit, as far as possible, has been made from the use of actual logs of wells, the locations of which are shown on the exhibit by vertical lines extending from the top of the exhibit, where miniature derricks have been shown, to the bottom of the exhibit. The reason the word "ideal" was used was because a portion of the exhibit in the lower part of it was not encountered by the wells shown. Wells in other portions of the field had encountered the conditions shown in the lower portion of the exhibit; but it was not possible to make a cross-section where those conditions existed and at the same time have a good portrayal of the actual gas-pay occurrences. This exhibit was made primarily to show the actual conditions of the gas producing formations, and for that reason was taken through wells where we had good measurements of the occurrences of gas in the producing formations. The red streaks shown on the exhibit
138 have all been plotted to scale from the actual occurrences of gas in the wells shown. Of course, it will be noted from the exhibit that those streaks cross each other at places where they are distant from the wells. Those are interpretations and nothing in the wells could show you that these streaks cross each other away from the well, but that was an idea that my experience there led me to think is the actual occurrence the way the gas occurs, and that is another reason why we used the word "ideal," although so far as I know that exhibit represents in every detail the actual conditions in the field—as actual as you could get a picture of them and have them right.

My attention is called to two little squares abutting each

other, across one of which is written the word "Hutchinson" and across the other "Carson," with an arrow and the letter "N" written in the middle of it, and over to the right of the arrow an irregular line with an "A" at the bottom and a "B" at the top. I am requested to explain those legends. The rectangular section shown at the top of the exhibit, one portion of which is labeled "Hutchinson" and the other "Carson," shows Hutchinson and Carson Counties and the actual position in those counties where this section was taken. The lines A-B I explain by saying that the A represents the south portion of the section, and B represents the north portion of the section, and the legend shows the plotted portion of the section as it was taken. That section is not in a straight line because I could not get adequate information on what I wanted to show if I went in a straight line. If I went in a straight line I would dodge these wells in which I wanted to show the conditions. In other words, if I had gone down there and cut a cross-section from A to B like you would cut a layer cake with a knife, I would not have been able to show the actual pay conditions that exist, because the wells in that section weren't where I could get them in a straight line.

The gray colored area at the bottom of this drawing, with a dark line above it, having two cones which are marked "granite" represents the granite core of the Amarillo buried mountain uplift. On the flanks of that mountain are colored areas on which I have written the words "granite wash." That represents the occurrence of the granite wash on the flanks of the granite ridge. On the left part of the exhibit that granite wash looks rather thick there. That is because this granite ridge at the time that granite wash was deposited was considerably larger than the part shown on the section, and as to the actual thickness as shown, the left border of the cross section shown is a log of a well and the oil pay shown in that part and projected to the right occurred in an actual well that was drilled in that portion, and the thicknesses were obtained from that well as to some of that granite wash.

This cross section was made by me in May, 1933. I did not prepare it as an exhibit for use in this particular case. It was prepared primarily for the use of the company and to form a basis for an exhibit shown at the Century of Progress Exposition in Chicago.

My attention is called to several perpendicular lines

coming down from the bottom of the objects which are small derricks along the surface. Each of those represents an actual well, the log of which was used in
139 making the cross section. The little derricks were put there just to show that they were actual wells and give an impression of the way things are on the surface. It was made for Exposition purposes.

The areas colored in green down at the lower end of each of the folds represents the occurrence of oil and represents actual oil occurrences shown by the wells used in that section. The right hand part of the section, to the right of the furthest well to the right, is not based on any log. I couldn't get any in there that would work. However, I had a log showing the existence of three oil-bearing layers or strata right in that vicinity, and the logs of other wells showed that those formations were continuous as shown on the section. They were sloping downward to the right. To the right on the exhibit means to the north. At the point where oil was encountered by well No. 1 coming south from the right hand side of the map and the log of the well next to it, No. 2 on the same map, coming in the same direction, shows that the formations which were encountered in the oil wells were sloping downward from No. 2 to No. 1 in a northerly direction, and I simply projected those formations on down to sea level. I stopped them there because I didn't want to carry my exhibit any further. If I had had the log of a well drilled at a point three-fourths of the way over from well No. 1 to the north side of the drawing, it would have encountered these formations below sea level and there would have been the occurrence of water there.

I do not mean by the drawing of the heavy black line labeled "Sea Level" at the north side of the map, to imply that these holes which are colored red in a portion of the map, and drop at intervals on the map, cut off at that dark line at approximately sea level. They would extend down into the water. I don't think anybody could know how far. Wells have been drilled over north and northeast of the limits of this field and the formations found to be saturated with water, then with oil, and higher up with gas.

The separate red bands represent separate gas pay streaks occurring in the formations encountered in the wells shown on the section. The tuba-like drawing almost in the middle of the map, almost directly over the most northerly peak of the buried granite mountain portrayed there, represents a typical case of the setting of casing in

a gas well. It was put in there for exhibition purposes. My impression was that they might erect a derrick at the Exposition, making an exhibit of it. It is just an enlarged picture portrayed by these black lines which I have described as wells. It is an actual reproduction of an actual log of a well, and the formations encountered by that tube or larger group of lines are actually found in the logs of wells of which that is supposed to be a picture. The elevations were determined by sea level elevations and measurements taken from the wells from the elevations at the surface down to where the formations were encountered. All the formations portrayed on this map are in their proper relation to each other and to the line which I have described as sea level. They are drawn to scale, both as to position above sea level and as to thickness and as to position with each other.

140 On this large tube-like well near the middle there is a smaller or dimmer extension from the region just above a little red short line down below the heavy red line. That represents the reduced hole that is drilled down after the casing is set. It shows the extension of the bore of the well down through the pay formations after the casing has been set. In other words, the hole is drilled larger than the casing down to the point just above the second red line, and that shows exactly where the casing in the particular well was set. That casing was set on the floor of the well at the time the casing was set, and cemented, and then the tools that would work inside the casing continued the hole down, leaving a shoulder which holds the casing in place.

A casing is composed of lengths of pipe screwed together. These lengths of pipe generally averages 20 feet in length, from 20 to 30 feet in length. In setting a casing in a well a shoe is attached to the joint of casing which is going to be set in the bottom of the hole and that joint is lowered into the hole and then another joint is screwed into that. The first joint is let down into the hole with a top screw above the surface a few feet. Then you screw it into another joint of casing and let it down another 20 feet, and you continue until you get down to the place where you hit bottom. Then you set it on the bottom and cement it.

In cementing a casing you raise the casing so that it is slightly off bottom, and the conditions of cementing a casing will vary, dependent upon whether or not you are cementing a well which is drilled with cable tools or a well which has been drilled with a rotary. I don't like to go

into the details of this process because I am not a petroleum engineer, but I can give you a rough outline that is correct. The cement is poured into the hole and pumped up around the side of the casing so that it goes down and goes up the sides of the casing and cements it to the rock and holds it in place, and it extends a little below the point where the casing stops. The casing does not fill the hole, but when the cement is around it it fills for two or three hundred feet up the hole.

After cementing they put the drill back inside the casing and come down to the bottom and drill the hole deeper, but, necessarily, they drill a smaller hole than the inside of the casing because the tools they are going to use to drill the bottom portion of the hole that goes through the pay have to go inside the casing. For this reason the hole that is drilled after the casing is set is necessarily of a smaller diameter. That is the projection which is shown in the bottom of that tube and shows the extension of the hole from where the casing was set down through the pay streaks.

The place where the gas gets to the bottom of the well and into the casing is an open hole. There is no casing in the smaller hole. Sometimes a liner is put in there. If there happens to be cave-in formation between the pay streaks, a slotted liner is sometimes set in so that the gas can go through it. That is the situation in certain portions of the field.

141 The gas gets into the casing from the red bands by going in the open hole which has been drilled below the end of the casing and going on up through that hole into the casing and on out to the top of the well.

The exhibit reflects the fact that the production from that well was from seven different layers of gas producing formation. The red line above the bottom of the casing was a little pocket of gas that was exhausted while the well was being drilled and there was no use trying to save it so we put the casing below it. The six below it all discharged gas into the open hole and produced gas through the casing. The several little short red lines at different parts of the dolomite are little isolated pockets of gas which have been found in some of these wells, some of which were exhausted very quickly, some not as quickly.

"Most of the isolated pockets of gas are located across the dark lines which represent wells but one is shown that does not cross one of the wells. That is because this is an

ideal section to show the way the occurrence can occur. They have been actually found in the wells that way. It is probable that you could find others that are not shown in those wells. We just could not, as a practical proposition, so locate the wells that we would penetrate every one of these pockets when we got through drilling at the field because of their regularity in their occurrence."

These little bands of productive area in the formation we call gas pay streaks. They are sometimes called lenses. By a lenticular producing formation I mean one which varies in thickness and size and shape.

"In speaking of a lenticular producing formation, I was talking about something that had to hold gas. The formations around it are also lenticular formations to which the same description as to shape applies, but they don't hold gas. In talking about a producing formation, the pockets are called pay streaks, besides lenses, the technical term is a lenticular body. Looking at a cross section of a lense, it might extend perpendicularly in both directions and cover an area comparable to the table. It would be a solid body and have all the dimensions of a solid body and would extend in every direction but it is just a gas pocket. It is not a hole they are just porous formations. The word lenticular means a plate shape formation that is filled with gas."

We find those lenses or small areas of producing formations scattered all over the field in our logs.

"You can tell when you drill a well through a lense instead of a band because the gas in them exhausts very quickly and the amount of gas present there is generally very small. We know it is a local condition when the wells on each side do not have that occurrence. Bands are found in every one of the wells clear across the formation."

The green colored part of the formation contains oil. Other portions of that same band have gas and water too, water below and free gas above, and there is a little soluble gas in the oil. From my knowledge of Panhandle crude and from an analysis made from similar crudes, there must be a very small amount of gas dissolved in the Panhandle oil. If wells are drilled, as our No. 1 well reading from the right, into the oil bearing formation below the place where the top porus formation passes down the structure out of the area of free gas, you get only oil with such gas as is in absorption with the oil. If that well had been drilled so that it would have come down about an eighth of

an inch to the south or to the left of where it is shown on the exhibit, and had encountered the red portion of the formation and also the green in the same band, you would have a flowing oil well producing both oil and gas. The oil would have been coming from the bottom of the hole from the portion of the formation which had oil in it, and the gas would be coming from the portion of the formation that had gas in it.

If the well had been drilled on down to the next two or three producing formations shown on the drawing, you would be producing oil from four different formations and producing gas also directly into the well from above out of the upper formations. There are situations comparable to that in the Panhandle field. Many wells have been drilled with those conditions that are both oil and gas wells in what we call the oil and gas zone of the oil field.

In a well like that, I would have set my casing above my first oil pay, first gas pay, also, if I had wanted to use that producing oil. By that I mean that if I had wanted to
142 produce oil and they would let me use the gas, I would try to keep the gas in there too and produce the gas with the oil. As to whether I know of any oil producer in the history of the field who would cut off that gas, I say no, he would like to use the gas all he could in producing oil. It would push the oil out of the well so he wouldn't have to pump it. He would also have a lot which he would call casinghead gas, which was the only gas at that time he could use for the manufacture of carbon black, and there was a strong temptation for anybody who had a well in that situation to complete it so as to get a maximum quantity of gas out with his oil, because he could prolong the production of his oil in a flowing condition by getting as much gas as he could into the well. He would also get a larger quantity of gas which he could sell as casinghead gas for the manufacture of carbon black and gasoline.

Questions by the Examiner.

The Railroad Commission, as I remember, about two years ago, began issuing reports which showed what they considered actual casinghead gas. These reports they issue in connection with their reports on the disposition of residue from gasoline plants, to show the proportion of casinghead gas produced. Before that time the gasoline plants had to make reports to the Railroad Commission

well by well of the gas that is produced from dry gas wells and from so-called casinghead gas wells. These reports show the actual wells which are producing the so-called casinghead gas. By going to the logs of the wells which the Railroad Commission or the gasoline plants have designated as productive of casinghead gas, you can very often determine where gas had occurred in the formations of these wells. That is the way I find out where the gas that has been designated as casinghead gas has come from, by going to the logs of the wells which are supposed to be producing casinghead gas and finding where that gas actually occurred as shown by the logs of the wells.

Our company doesn't happen to have any casinghead gas, but gasoline plants have to report it. The gasoline plants are the ones that generally use casinghead gas from the wells. They make gasoline from it, so they have to report all the wells from which they produce casinghead gas.

For a good many years there has been no precise term for the definition of casinghead gas. In the history of the production of the field it has been a very loose term. If a gas came out of a casinghead, it was casinghead gas. That is about the only way it was used. I believe there has been a statute written defining casinghead gas, but it has not been in effect very long.

I understand that the Examiner wishes to know what it is the Railroad Commission calls casinghead gas in their reports, and not the legal definition. I understand he is not talking about chemical or legal or any other kind of definition except the Texas Railroad Commission's as
143 contained in its reports. In the reports made by the Texas Railroad Commission, by casinghead gas is meant any gas which is produced from a well which has oil in it, whether the gas comes from the oil or in the oil or comes from the formation above the oil formation. If it is produced in a well that has oil in it, they call it casinghead gas. As I said before, the way I find out whether casinghead gas is being produced from a well that is said to be producing casinghead gas in large quantities is that from the records of the Railroad Commission's office I can see that certain wells are stated to be producing casinghead gas to these gasoline plants, and an examination of the log may show that this well had amounts of gas in the formations above the oil producing formations, and that this gas has not been cased off, and, therefore, it must be coming

from the formations that are above the oil formations, and that is why I say that many times I can tell whether a gas produced from a well is real casinghead gas or not.

Direct Examination Resumed by Mr. Morgan.

Well No. 1 on the chart, reading from the right, or from north to south, is shown as encountering only the oil producing formations, so it would produce a very small amount of casinghead gas, but its production would be true casinghead gas.

I have noticed in the Railroad Commission reports references to wells having no gas-oil ratio. That means that that well produces its oil without producing any gas. It would be a well which penetrated the oil bearing formation and produced only such gas as is found in absorption in the oil, and the Railroad Commission has seen fit in its reports to treat that as none at all.

In my experience as a geologist in the Panhandle and from my study of the logs of oil wells in the Panhandle, I have never seen a log that indicated the presence of a catchment basin carrying free gas in the oil producing part of the formation and occurring directly above the oil. I heard Mr. Brown talk about a catchment basin. His term, as a matter of fact, is a very strange term to me. You state that, as you understand it, a catchment basin is a projection out from a portion of the oil bearing formation which carries free gas and not mere gas in absorption. I don't know of any such a situation. Gas in the producing formation will occur sometimes above the oil. That is natural. I never heard of a catchment basin or porous area down in the oil producing part of the formation which carried free gas. I don't know of any such occurrence in all the wells we have drilled in, that is, Texoma, where we have drilled through the gas producing formation, and we have done it a number of times, we have drilled down to where there were oil shows underneath our gas producing formation, and I do not know of any occurrence that we have had where the gas ever occurred below the shows of oil, except in one freak occurrence where we have oil occurring where gas ought to occur and gas occurring both above and below the oil. That is one freak occurrence in one of our wells; but that would not be a catchment basin. That is an occurrence of oil rather than gas.

I have studied a great many logs of oil wells in the

Panhandle field. I have studied all the available logs of gas wells and all the available logs of oil wells that I was particularly interested in near the gas areas. I haven't
144 gone into all the available logs of all the oil wells.

In all the logs I have ever examined, I have never found any such situation as a gas formation down below the level of the pink lines or ribbons on that drawing and in the oil producing part of the formation.

Inside the heavy black lines and north of the colored part of the map on Exhibits 21, 22, 23 and 17 is shown a very substantial area on which are groups of small black spots. That is a portion of the oil area which has no free gas in it. It is a portion of the field that sustains the same position with reference to the gas bearing formations as typified by well No. 1 on the cross section of Exhibit 16, which enters only the formation which is colored in green. Those little black spots are oil wells, whether they be on the colored or uncolored portion of the drawing. There are oil wells which produce where gas can be produced also. There is a large area of production of both oil and gas. Those are the wells that are situated, with reference to the producing formations, somewhat as are set forth in wells Nos. 2, 3, 4 and 5, reading from the right on Exhibit 16. If a well be drilled in the position of wells 5, 4, 3 and 2, you can produce both oil and gas from that well. That is the situation that obtains where we find these black spots or groups of black spots within the colored area. That is the oil and gas producing portion of the structure. To be specific, those black spots on Exhibits 21, 22, 23 and 17 which are within the colored area are intended to represent wells which were drilled to oil producing formations, but through gas producing formations, and are capable of producing both oil and gas; but those black spots out in the uncolored portion along the northeast flank of the field are meant to portray wells which were incapable of producing free gas and produced only oil and such gas as was found in absorption in the oil.

Questions by the Examiner.

I have made no detailed cross sections for different parts of the field, other than Exhibit 16. I have made rough drawings for my own purposes in different parts of the field, but have not made them permanent records. I have used them in trying to find out how the situation

was in different localities. This cross section conforms generally with all of the producing conditions of gas and oil in the field. I don't consider this exhibit to be particularly favorable to my testimony. The other cross sections would show the same general conditions, but they would show faulting some places to the south. If I took a cross section along the south part of Potter County in Exhibit 23, I would show a fault there, south of which is no gas production, or some other detail of that kind. So far as the occurrence of gas and oil is concerned, I think that is as good a general representation of the field as a whole as can be obtained. There is no distortion derived from the fact that these various zigzag planes are swung into one plane, except only the amount of dip—whether it was a little steeper or a little flatter.

"This zigzag is made up of a series of turning points and there are no wells between them. It has as many lines indicating wells as I have turning points which are drawn to a rough approximation of the scale just to show the general location. In making my section, I tried to get the proportions as close as I could. There isn't any distortion which would make any difference in the occurrence of the gas and oil. Those wells are not so far apart really as appears from the map. They are merely taken because each one of those wells had a good definite record of gas pay, and also of oil pays."

The location of the line A-B on Exhibit 16 can be located on Exhibit 21. Starting about the center of "o" in "Carson County" and extending northeasterly from Section 13, to Section 10, and then extending to a little beyond the "R" in the caption I&GN Railroad, Block 4, and the northwesterly to the section which is about two miles northwest from the town of Skellytown on the 145 exhibit, it then extends northeasterly to a point about one mile south of the small letter "a" in the word "probable," and then a little further north.

The mountain cross sections are more or less ideals from occurrences in wells that are not on this cross section.

On the section a number of miles to the west from where I took this section, this granite was recorded in a well which showed the elevation of the granite ridge, and these wells you have noticed have gone into that granite wash. The line that forms the left border of the cross section shown on Exhibit 16 represents the actual lines of

a well, and the oil occurrence shown in that well on the section actually occurred there, but it was extended to the north to show that this oil did not just occur in a little bit of a pocket. The right hand line of this cross section does not indicate a well.

(EXHIBIT 16 for identification, offered and received in evidence without objection.

Photostat copy of pages 43 to 48, inclusive, of documents entitled "Railroad Commission of Texas, Annual Report on the Panhandle Oil and Gas Field, July, 1938," marked Exhibit No. 26 for identification.)

(May 29, 1939.)

Direct Examination by Mr. Morgan Resumed.

Exhibit 20 was prepared under my direction. That exhibit portrays the classification of gas acreage which I used in making my estimate of gas reserve for the Texas Panhandle field. On that exhibit there are two classifications of acreage. First, the acreage on which wells are encountered with open flow above five million cubic feet per day, which I called the best commercial gas acreage. Secondly, marginal gas acreage, which is gas acreage on which the initial open flow of wells is below five million cubic feet per day. This refers to initial open flow in each case.

The acreage colored in yellow on the map is that on which wells have an initial open flow of five million cubic feet or more per day. That is classified as the best commercial acreage. The acreage having wells with less than five million cubic feet per day is colored gray on the exhibit. The acreage colored yellow, showing the best commercial gas acreage, contains a total of 1,033,970 acres. The area colored gray, which I described as marginal acreage and in which the initial open flow of wells is less than five million cubic feet per day, contains 432,967 acres. 676¼, or just a little below 700, square miles is included in the gray area.

I have computed the weighted average pay thickness, or the weighted average thickness of the formations yielding gas, in the yellow area. In estimating the reserves of the yellow or best commercial gas acreage, I computed the weighted average thickness of the gas pay streaks in that area. Also by a study of the formations and of well cuttings, and all the geological information

available, including geological information available in other fields, I arrived at a porosity of 20% for that acreage. I mean that 20% porosity would be the average to apply to that acreage. I do not mean that every acre would have 20% porosity in it. Some of them would have greatly higher porosity, and some of them greatly lesser porosity.

146 I have computed the reserves of natural gas underlying the acreage colored in yellow on the exhibit, using a pay thickness of 70 feet and a porosity of 20%. Those are the same factors for pay thickness and porosity used by Mr. Brown in one of his estimates. I do not apply it to the same area to which Mr. Brown applied it. My application is different from that which he used. In determining what factors to use I had to consider all the wells drilled in the area colored yellow, and to that yellow colored area this factor absolutely applied. There is considerable difference in conditions in the yellow area and in the gray area. The yellow area is situated in a better structural position as a whole than the gray area. By that I mean that it is the general rule in the Panhandle as a whole that the best productive acreage occurs in a relatively high structural position. The area colored yellow on Exhibit 20 is on the whole in a relatively high structural position as compared with the area colored gray. By that I mean it is further up the slope of the old buried granite mountain range. Its position is higher on the flanks and top of the old granite ridge. It is further away from positions where water would be encountered, and also the thickness of the pay streaks as defined by development in the pay areas is considerably less as an average in the gray area than it is in the yellow area. Also, an examination of the action of the wells which have been drilled in the two areas, and of the samples in these wells, shows that the pay streaks in the gray areas in many cases are a great deal tighter than the pay streaks in the yellow area.

By pay streaks being tighter, I mean that the porosity and permeability of these pay streaks is considerably less than that in the yellow area. The gas will not flow with the same facility through the formation; and there is a smaller amount of it present in this area.

My attention is called to two general areas of gray extending clear across from the south to the north side of the field. In that area the wells that have been drilled

to date, and numerous dry holes, have shown the area to be tight, and of a low gas productivity. A great portion of that area shows thinness of pay streaks. The main thing about this gray area extending clear across the field just east of the area in which there is a kind of an island of unproductive area is the evidence of low productivity shown by the wells drilled in it and the evidence of thinness of pay streaks encountered by the wells drilled on it.

I have already stated that this area which I have described as an island of no productivity is low structurally. There is a dip in the formation at that point. This area is bounded on the north by a fault which has thrown it down with relation to the area north of it, and the area south of it dips into this area, which makes it an area of depression structurally.

Coming over to the east end of the field, the gray goes clear across between the Osborne field and the yellow area of Wheeler County. In this area there is a combination of low structural condition and thinning gas pay streaks, a particular lack of porosity and tightening of the pay streaks.

147 Had I averaged this 676½ square miles of area colored in gray into the yellow area and treated the field as a whole, and applied the factors of 70 feet of pay thickness and 20 per cent porosity, the result would be a greatly distorted representation of the actual conditions in that field. The gas area contained in the yellow is of such high productivity that if gas areas of very small productivity were averaged with them, it would give the idea that the whole field would be of good gas productivity, whereas the opposite is really the case. For instance, in the gray area, which embraces a little less than 700 square miles in extent, I would not recommend the drilling of a well for gas at all.

I have made a separate computation of the reserves of this gray area embracing nearly 700 square miles. I based that upon a study of the geological structural conditions in the different portions of that area, upon the thickness of formation encountered in the wells drilled in the gray area, and upon the relative porosities shown by the productivity of the wells drilled in that area. I had assistance from wells other than those which have been drilled in the gray area in arriving at my deductions. I used the wells drilled in the gray area in some instances

in combination with dry holes drilled outside of the gray area to be able to determine the structural conditions that existed in the gray area. In other words, knowing the structural position of the pay, that is, the altitude above sea level of the pay formation along the south border of the yellow area, and knowing the structural position at which the formation yielded dry holes in the field south of the gray, I had satisfactory information concerning the structural position of the formations in the gray. The information shows how high it will be structurally, or what position it might come in contact with oil or water. Quite a number of dry holes have been drilled around that gas field. That is what helps define the boundary of the field. You know where the gas is because they get outside the clearing and get dry holes.

I have not made a computation of the gas reserves in the field based on the pressure decline method. I didn't do that because, on account of the variability of geologic conditions and the impossibility of obtaining equalizing of rock pressure, and the infinite variety of complications which are attached to the field, this was not practicable. It is not possible to get the right result.

In an application of the pressure decline method of computing reserves, the correct pressure factor to apply is that of equalized pressure. In other words, if you knew the pressure at which the field would equalize if every well in the field were now shut down and not permitted to produce until the pressures were the same all over the field, then the pressure decline method of computing reserves could be safely applied, with some other factors present also. If you knew that ultimate equalization pressure, it could be safely applied; but that pressure is not known. It cannot be computed in the light of the physical conditions and the pressure conditions which obtain in that field.

148 If the field had been so produced that every part of it had yielded up natural gas with the result that every well in the field and every acre in the field would now have the same pressure, the pressure decline method could be used; but that is not the condition in the field. That is one of the conditions it would be necessary to have.

If every acre in the field had exactly the same quantity of gas under it as under every other acre, then the pressure decline method of computing reserves could be used;

but that condition most certainly does not obtain in the field.

I have made an estimate or calculation of the average pay thicknesses of all the wells of Texoma. The pay thicknesses in the wells of Texoma range from 10 feet to 185, an average thickness of 79½.

I have a tabulation of the initial open flow of all the wells of Texoma. They range from 3,400,000 cubic feet to 114,515,000 cubic feet, having an average initial open flow of 29,203,000 cubic feet. Of these wells five or six were drilled in while the pressure was still virgin pressure. They were drilled before we acquired the property; that is between 1920 and 1926, back in the early days of the field. None of the wells drilled since Texoma acquired the property had a pressure of 430 pounds at the time it was drilled.

(Document entitled "Texoma Natural Gas Company Wells, 1931 to May, 1939," marked Exhibit No. 27 for identification.)

Exhibit 27, entitled "Texoma Natural Gas Company Wells, 1931, to May, 1939, Thickness of Pay and Initial Open Flow, C. J. Peterson, Witness," is a tabulation prepared by me. It is a correct list of the wells which have been drilled since Texoma acquired the properties, and the pay thicknesses of those wells and the initial open flow of each of those wells, together with the average pay thickness and the average initial open flow, and also of wells which were acquired by Texoma at the time Texoma started production. It includes both those wells which were bought as well as those which Texoma has drilled. In other words, it includes all of Texoma's wells.

(EXHIBIT NO. 27 for identification, offered and received in evidence without objection.)

I have records showing the pay thicknesses and initial open flow of all wells which were drilled prior to the time Texoma acquired them, and I have such logs of those wells as were in existence.

I have prepared estimates of the total original reserves of the acreage identified on Exhibit 20 in yellow and in gray and have combined those estimates, and now have estimates of the total original reserves of gas in the entire field. I applied in computing these estimates a recovery factor of 90%. I did this because it has never been possible to recover 100% of gas reserves in any gas field that I know of. The Panhandle field is a com-

plicated field, with immense variation in porosity and thickness of pays, and the reservoir is not an ideal gas reservoir. It is subject to various imperfections, and there are a great many things which tend to prevent the recovery of gas in the field. That observation applied to reserves at any assumed abandonment pressure.

149 The conditions which make it impossible to recover 100% of the gas at any assumed abandonment pressure at the wellhead are, first, because at any assumed abandonment pressure the pressures in the areas surrounding the well at which any assumed abandonment pressure is used would be higher than the assumed abandonment pressure, for which reason gas would still exist in the reservoir at pressures which are higher than the abandonment pressure used. Secondly, due to the faul completion of the well and the conditions which have lowed upper waters to pollute the gas pay streaks, and ive allowed bottom hole waters to pollute the gas pay stre ks, there now exists, and more will exist in the future, area where already water has been allowed to enter the gas pay streaks and cut off portions of the productive gas area, so that there will be gas entrapped in those areas. Also, some wells, although at comparatively high rock pressures, have become impossible to produce, and no operator will be desirous of drilling in those areas, where there is still some gas, but which is so polluted with water that they will not even attempt to recover it. This means that it is impossible to recover 100% of the gas in the field.

The bottom hole water is regular brine salt water, and the water that often comes from the upper formations has to pass through formations which contain immense amounts of salt. These formations which show salt are shown on Exhibit 16, labeled on the margin "Salt Series." When water passes through this section containing large amounts of salt it becomes heavily saturated with salt, and then when it gets into the well it has a tendency to enter the pores of the gas producing formation and salt off the gas so it can't get back in the well. By that I mean saline deposits. This salty water has two adverse effects upon the productivity of the sand. It will drown out the gas when it enters from the bottom, and it will salt off the gas formation when it becomes crystallized on the sides of the well.

Texoma has had to abandon seven wells. The last official pressures taken of those wells prior to their abandonment

showed that they had an average abandonment pressure of 159 pounds. A considerable number of other wells in the field have had to be abandoned by reason of those conditions. I know of some of the data on those wells, but I have not personally compiled it.

You refer to a triangular shaped yellow area near the east end of the field in Wheeler County and another area to the south of the island of no productivity in the middle of Gray County, both areas being shown on Exhibit 17, and ask if it is my view that all the gas contained in those areas will be produced at any abandonment pressure. My answer is no. I believe there is no inducement for operators to drill in those areas, for which reason wells would not be drilled in them. Of course, there is some drainage from those areas; but the formations are so tight in those areas that it is not likely that the full amount of gas will be drained out, for which reason it would seem that there will always remain some gas not recoverable in those areas. I say it is not likely, which is rather a conservative statement to make. If it were coming out of there now, the pressure conditions there, instead of being 400 pounds, would be a greatly reduced pressure, as is shown in the adjoining 150 area. The reason it is not as low in the middle of the triangle as on either side of it is because of the tightness and the very small well in the center of that yellow area. There has been very little gas produced from it, while immense amounts of gas have been produced around the edges, which has not pulled the pressure down in spite of that fact.

I have computed the total original reserves of the Panhandle field, applying a recovery factor. I have computed the original recoverable reserves at assumed wellhead abandonment pressures of (a) zero pounds; (b) 25 pounds; (c) 50 pounds; (d) 75 pounds; and (e) 100 pounds. I made the five computations because I am personally unable to determine what abandonment pressure should be used.

(Document entitled "Natural Gas Reserves, Texas Panhandle," marked Exhibit 28 for identification.)

Exhibit 28 is now submitted to me. I have said I am unable to determine the abandonment pressure of the wells. I have been working in that field practically nine years, devoting my entire time there as a geologist. I say that I can't tell what the abandonment pressure will be because it is absolutely purely economic as to what abandonment pressure should be used. The abandonment pressure for

different projects would be entirely different. For instance, the abandonment pressure which might be applied to a carbon black plant would rely upon factors which would be entirely different from those which would apply to a natural gas pipeline which was transporting gas through a pipeline for approximately 1100 miles. In the case of a pipeline, for instance, the market rates might stay the same, but as the years go on there is an increase in the costs of producing gas in the field—an ever increasing cost.

I might be able to determine whether or not, if wells were not spoiled by pollution of the gas pay streaks, they might produce certain amounts of gas at certain abandonment pressures, in case they were not flooded out by salt water or something else, but this would not be a determined abandonment pressure. The abandonment pressure is purely an economic question.

I have prepared Exhibit 28 on several abandonment pressures, so whatever the evidence shows the proper abandonment pressure to be the figures will be here. I have just carried them to certain figures. It may be that further figures will be required; I don't know. We might have to go to 150 pounds or 125 pounds. If it falls within this range of zero to 100 pounds, I have the figures here, by steps of 25 pounds from the lower to the higher assumed abandonment pressures.

In my judgment, the total recoverable reserves originally contained in the Panhandle field at an assumed abandonment pressure of zero pounds at the wellhead were 16,955,758,431,000 cubic feet.

At 25 pounds wellhead abandonment pressure, my figures are 15,991,092,936,000 cubic feet.

At 50 pounds wellhead abandonment pressure, my figures are 14,989,327,612,000 cubic feet.

151 At 75 pounds wellhead abandonment pressure, my figures are 13,987,579,763,000 cubic feet.

At 100 pounds wellhead abandonment pressure, my figures are 13,022,914,269,000 cubic feet.

These reserves were computed by me on a pressure base of 16.4 pounds per square inch, and based on a 90% recovery factor.

I have computed the recoverable reserves of the Panhandle field still remaining after January 1, 1939, at the same well head abandonment pressures, and have applied the same recovery factor in these computations as I did in

those I have just stated, and used the same pressure base of 16.4 pounds per square inch.

(Without objection Commission counsel observed that there was no necessity for reading figures into the record which already appear in the exhibit.)

The recoverable reserves still remaining in the Panhandle field on January 1, 1939, at an assumed wellhead abandonment pressure of zero pounds per square inch, were, in my judgment, 9,799,519,611,000 cubic feet.

At 25 pounds there were 8,834,854,116,000 cubic feet.
At 50 pounds there were 7,833,088,792,000 cubic feet.
At 75 pounds there were 6,831,340,943,000 cubic feet.
At 100 pounds there were 5,866,675,449,000 cubic feet.

I have also computed the original recoverable reserves underlying the acreage owned by Texoma as of January 1, 1939, at the same assumed abandonment pressures, and applied the same recovery factor, on the same pressure basis.

My estimate of the original recoverable reserves underlying the acreage owned by Texoma on January 1, 1939, was as follows:

At zero pounds, 2,744,518,086,000 cubic feet.
At 25 pounds, 2,588,373,970,000 cubic feet.
At 50 pounds, 2,426,224,748,000 cubic feet.
At 75 pounds, 2,264,078,354,000 cubic feet.
At 100 pounds, 2,107,934,238,000 cubic feet.

I did not use the same sand thickness in computing Texoma's reserves as I used in computing the reserves of the area colored in yellow on Exhibit 20. I used the sand thicknesses which were shown for the wells drilled by Texoma as applicable to the areas where those wells were. The leases of Texoma were divided up into tracts which were mostly of 160 acres or less, and each tract was
152 carefully appraised and figured. I based the computation on the actual sand thicknesses underlying Texoma's leases, lease by lease, and subdivisions of leases when it was necessary to subdivide. In many cases the leases had to be subdivided into many parts to get the correct estimates.

I have also made a similar computation or estimate as of January 1, 1939 of the reserves of gas underlying Texoma's acreage which it owned on January 1, 1939. Those computations were made in the same way.

It is my judgment that the recoverable reserves under-

lying the acreage owned by Texoma on January 1, 1939, as of that date, were as follows:

At zero pounds, 1,989,662,119,000 cubic feet.
At 25 pounds, 1,833,518,003,000 cubic feet.
At 50 pounds, 1,671,368,781,000 cubic feet.
At 75 pounds, 1,509,222,387,000 cubic feet.
At 100 pounds, 1,353,078,272,000 cubic feet.

I have prepared a tabulation showing the gas that has gone out of the formations underlying Texoma's acreage which it owned as of January 1, 1939, including gas produced from its wells and that drained to other wells. This tabulation is broken down so as to show the production from Texoma's wells separated from the drainage to other wells or areas. In arriving at the figures shown by that tabulation I first secured the original recoverable reserves of Texoma's acreage to zero pounds abandonment pressure at the wellhead. Then by taking each separate tract of Texoma's leases and applying to that tract the rock pressure correction which was indicated by the rock pressure occurring on that tract at January 1, 1939, I computed the present reserves on Texoma's acreage. Applying the requisite abandonment pressure factor, where I am using in this tabulation an abandonment pressure of zero pounds gauge at the wellhead, I obtained the results shown on the tabulation.

I have already stated that the original reserves at zero pounds were 2,744,518,086,000 cubic feet. That is shown on my third set of figures on the first page of Exhibit 28. The recoverable reserves at the same assumed abandonment pressure as of January 1, 1939, are shown in the last set of figures on page 1 of that exhibit, which shows them to be 1,989,662,119,000 cubic feet. It is just a matter of deducting the January 1, 1939, reserves from the original reserves, and the result is a total loss to the reserves underlying Texoma's acreage amounting to 754,855,967,000 cubic feet.

Taking into account the gas produced from Texoma's wells prior to the time the company acquired those 153 wells and during the time the company has produced those wells, the total production was 284,852,785,000 cubic feet; so, in my judgment, there has been drained away from Texoma's property to the wells of others 470,003,182,000 cubic feet. Therefore, of all the gas that has moved out from under the lands of Texoma, there was lost by Texoma through drainage to other wells 62.26%.

The result would be the same if you were to take the same comparable figures at an assumed abandonment pressure at the wellhead of 25, 50, 75 or 100 pounds. It comes out exactly the same. That is the reason why I haven't given it for every abandonment pressure; but I have calculated it and it comes out the same for each of the subsequent abandonment pressures.

I have prepared estimates of Texoma's reserves, original reserves and subsequent reserves, in connection with other litigation prior to this time. I made estimates of the reserves of Texoma's properties in litigation which Texoma had with the Railroad Commission of Texas. I testified by affidavit two times and as a witness one time. I did not use a recovery factor in the estimates I made in that litigation, because I did not in that litigation estimate any recoverable reserves. In that litigation my estimates were for the purpose of determining the amount of gas underlying the Panhandle field and different portions of the Panhandle field, and the whole idea in making those estimates was to arrive at comparisons of different areas in the Panhandle field and to figure what drainage had occurred between the different areas. For this reason no recovery factor was needed. The amount of gas recoverable from the Panhandle field was not at issue in these cases. The life of the field was at issue. The issue was to determine whether or not the drainage was from or to the properties of Texoma, and the computations had to do only with drainage between different areas. It had nothing to do with the recovery of gas. The percentage and the picture as to drainage would have been the same in those cases had I applied a recovery factor. They would have come out exactly the same had a recovery factor been used.

I have not at all times used the same recovery factor in my computations as that which I have used in the computations concerning which I have just testified. I have been continually studying conditions in the field and have had different tentative recovery factors in mind at different times. In September, 1938, I had in mind a recovery factor of 95%; but this was just a tentative factor, and after very careful consideration of the different conditions in the field and of developments which entailed the abandonment of wells, I arrived at a factor of 90%, which I believe is more reasonable than 95%. I have never used

the 95% factor for any purpose whatever. It was just a tentative factor I was mulling over in my mind and trying to get the right one.

Questions by the Examiner.

The estimates I made in connection with the litigation with the Railroad Commission of Texas were not on a comparable basis for the original recoverable reserve at zero pounds. I remember I stated my reserves at that time had an abandonment pressure of 25 pounds.
154 This was just for the purpose of litigation, and any per cent for drainage figured out about the same as it did here except that because of the time interval it was a little different. So far as I know, there was nothing fundamentally inconsistent with the results in that case and the results I obtained here, except that my estimates of reserves were different than they are now, as I did not have as much information. The acreage in the field was different and I had less information on the pay streaks, and I did not have the information available to make as correct an estimate as I can make today.

In reply to the inquiry as to whether in the gas produced I included an estimate of gas used in bringing the wells in and other miscellaneous losses, or whether I figured that into what I call drainage, I will state that the gas produced took in the total amount of gas produced from the company's wells. The company bought some of those wells at a certain period, and a certain amount of gas had been produced from some of the wells before they bought them. This figure of gas produced included the gas that was produced from the wells prior to their acquirement by the company and also included all the gas that the company produced from the wells. It does not include the gas that was popped off in drilling the well. It does include the gas that was used for fuel. That gas that was popped off was not very large for each separate well. Since it is not included in production, it would be included in the loss embodied in drainage; but as compared to the rest of the production it is a very small quantity. It would be less than 1%. At the present it is included in the item called "Drainage". The figure 62.26% probably should, because of that gas lost in drilling in the well, be 61 and fraction per cent.

Direct Examination Resumed by Mr. Morgan.

Exhibit 28 embodies the figures concerning which I have testified and shows my tabulations as I have stated them into the record, subject to the modification concerning the gas popped off to the air in connection with the completion of wells.

(Upon offer of Exhibit 28 it was objected to by Commission Counsel and Counsel for Illinois Commerce Commission on the ground that no foundation had been shown for the calculations.)

I went over my work sheets and computations with Mr. Claude C. Brown, a representative of the Federal Power Commission, in detail and gave him a copy of them. They differ slightly from the sheets I gave him in that at the time I gave them to him I had not definitely determined what recovery factor to use.

Without resorting to the arithmetic involved, but confining myself to the method I used in computing the reserves of the field and of Texoma's properties as shown in Exhibit 28, I will state that I first classified my acreage by two classifications, the first classification being the acreage on which wells drilled would have an open flow above five million cubic feet per day, and the second classification being the acreage on which wells drilled would have an open flow of less than five million cubic feet per day. Having done this, I determined for the acreage on which the wells drilled had an open flow of over five million cubic feet per day the average thickness of the pay, weighted by acreage and the average porosity. In determining that 70 feet was the weighted average pay thickness, I went over the area in detail and ex-
155 amined the records of the wells all over the area and got the weighted average per acre thickness of the pay streaks. I arrived at my 20% porosity factor by careful examination of the samples and by referring to records of other people who had done the same thing, and by comparing the productivities of the wells. Then, having ascertained these factors, I used the porosity thickness method in obtaining my reserves in that area. 20% porosity is the generally accepted figure for the average porosity of the better part of that field by the geological fraternity. It is mentioned in several publications.

As to the yellow area, I used exactly the same method that Mr. Brown used when he arrived at his content per

acre, and obtained the same content per acre for the yellow area that Mr. Brown has used for the whole field. I mean that I obtained the same average per acre content. The only difference between what I did, so far as the yellow is concerned, and what Mr. Brown did was that I applied a 70 foot pay thickness and a 20% porosity for the part colored in yellow, embracing about 1,032,000 acres, whereas he applied the same pay thickness and porosity factor to the entire field. I did not apply it to the entire field because I did not think it was applicable to that part of the field colored in gray, embracing about 432,000 or 433,000 acres, because the facts that are applicable to the gray area do not show that state of affairs at all.

In computing the reserves in the gray area I went into the separate divisions of the gray area and determined for each separate division the per acre content, using the porosity method and the wells that were existent there to determine those factors. I can tell you exactly how many separate divisions I used in the gray area. I have all the figures here.

(Upon request, Company Counsel refused to make available the work sheet underlying Exhibit 28. Ruling on the exhibit withheld by the Examiner.)

Cross-Examination by Mr. Booth.

Counsel has asked me to describe for the record all of the data upon which the computations shown in Exhibit 28 were arrived at. (Colloquy between Counsel for Illinois Commerce Commission and the Examiner with respect to a request for all data, reports and investigations underlying the witness' conclusions set forth in Exhibit 28.) It seems to me I have already done that. I have some of my working papers here. First I will tell you how I got my thicknesses and where they were. I will go into how I got the column of gas, the weight of the column of gas, and its extent, used in determining my average weight of the column of gas used in these reserves. I will go through all that and tell you about all that if you wish. Part of the data is on file in the office of Texoma in Amarillo and I have some of it here; but if I am going to get these in the record it will take two or three hours to do it, but I will go right ahead and do it.

(Upon request by Counsel for Illinois Commerce Commission that in order to save time, representatives be designated to consult with witness to see what working papers the witness had in connection with Exhibit 28, a colloquy was had between Examiner and Counsel on the request.) I am asking for a little more time to get all my data together in order to show the information shown on this tabulation.

Questions by the Examiner.

I propose to take the gray area shown in Exhibit 20, divide it into sections—the sections in which I divided it in making my estimate—and assign to each section a number. Using these numbers as a key to the map, I will show for each one of the numbers the number of acres involved, the average thickness of pay used in that area, the porosity determined, the per acre reserves, and the 156 reserves for the area, and also I might put in some remarks showing the geological reasons which are involved, or some development reasons, such as the twenty dry holes, and things of that nature. I can say right now that most of these data have been determined by myself, without any text books of any kind or any other reports, but just from my experience in the field.

I have stated that I prepared and submitted affidavits to the Railroad Commission of Texas dealing with gas reserves. That was in 1932 and 1933. Counsel for the companies has stated that the cases are reported in 4 Fed. Supp. 222; 59 Fed. (2) 750; 2 Fed. Supp. 168; 300 U. S. 55; and 14 Fed. Supp. 318.

Cross-Examination by Mr. Slaff.

The citations which Mr. Hedrick read cover all the cases in which I have testified while I have been with the company. I haven't written very many publications because I have been so tied up with company business that I have never been able to get the time; but there is one publication I can refer to, which was written for the Oil & Gas Journal. It was a publication on the conditions of natural gas in the Mid-Continent and North Texas field, written for the natural gas symposium which the Oil & Gas Journal published. If I knew the date I would be glad to tell you. It was around 1928 or 1929. Since then

I have written no papers; I have been too busy to write anything. It is a wonder to me how a lot of these men who do commercial work get enough time to write papers.

I have not testified before any administrative bodies or any Legislature or legislative committee in the last ten years, except one case when the Texas Senate conducted a hearing in Amarillo, when I testified regarding some rock pressure conditions in the field. That was about 1934. That was the only time I have testified in addition to the cases the citations of which Mr. Hedrick read.

Redirect Examination by Mr. Morgan.

Counsel for the Federal Power Commission has made a statement indicating that there was a misunderstanding as to what I testified with respect to the information I turned over to Mr. Claude C. Brown. I have been requested to state what I did turn over to him. As a basis for my reserve estimates for the Texas Panhandle field I assembled a number of tables, numbered 1 to 10. These tables gave the basic data for the reserve estimate, with the exception that table 8 apparently did not go into the detail that Mr. Brown wanted. The details behind table 8 are a voluminous mass of information, and I thought I had given him all the basic data when I had given him the results of the tabulation of that mass of information.

I gave him a copy of the pressure map for 1938, which is Exhibit 17, except that it was not colored. I also gave
157 him a copy of Exhibits 16 and 20. I did not refuse to give him anything he asked for. I gave him Exhibit 13, except that he drew a line on it. I did not put the red line on there.

(Mr. Brown here states to the witness that when the witness gave him Exhibit 13 it had everything on it it now has with the exception of the purplish line, which Brown placed on it, indicating what the witness thought was the best commercial area on Exhibit 20. The witness agrees that that is true.)

Questions by the Examiner.

It would be possible to compile a production map breaking down the content of Exhibit 24 into production bars for the various years. It is possible to create production bars

for the various rock pressure zones for any number of typical years; but I have never been able to get time to collect that information because the zones are shifting. It would be necessary to get the production from every well in each zone, which is a rather tedious job.

The only reason I do not have rock pressure maps for 1933, 1934 and 1936 is that I did not make them. Another reason is that in 1933 the information was not complete. It would have shown a very poor result to have made that map up. In 1934 the same conditions were in existence, for which reason I did not like to use the data that they had because it would not give as good control. It took about two months' preliminary work to make the 1932 map making sure of the location of the wells, getting all the rock pressures, and locating it accurately. The contouring takes about two weeks straight time, and then the coloring after that.

By porosity we mean the percentage of voids in a formation; that is, the percentage of the formation which has voids in it—speaking of the voids in that formation as a percentage.

By permeability is meant the ability that a liquid or a gas has of flowing through the formation. It is meant to be an expression of the ability that gas or liquid, such as oil, has of passing out of the formation and flowing. It is the flowing ability. It has to do with the power that liquid or fluid has, the rate at which it can flow against resistance. Permeability to me has always been a difficult term to define exactly. It is the ability of the formation to allow a liquid or gas to flow out through it. In other words, a substance could be quite porous and might have a high coefficient of friction. It is the ability the formation has of allowing the liquid or gas to overcome the friction.

In my estimates of the reserves in the gray area, I have taken no account of depletion. The figures I have given here are an estimate of the original reserves.

I will give you my conception of the buried mountain range. As far as I can determine, it runs along the structural axis of the field. The granite ridge has not been drilled in a number of places in the field, and that is the reason why we have to use this axis as our location of it, because it has not been definitely located by drilling in every portion of the field. The approximate location of the Amarillo mountain ridge, so far as we are able to determine, extends on Exhibit 17 from a point in about the cen-

tral portion of part of Potter County which is shown within the limits of the boundary of the field, eastward to about the junction of Moore, Potter, Hutchinson and Carson Counties, and thence in a southeastward direction to a
158 point which is in about the center of Block 5, I. & G. N. R. R. Co. survey, and thence in a southeasterly direction to a point about six miles north of White Deer in Carson County, and thence southeastward to the southeast corner of Section 155, Block 3, I. & G. N. R. R. Co. survey.

It must be understood that in this buried Amarillo mountain range, there are high places and low places. I have tried to give you the axis of the highest part that I know of. As we come into the area in the middle of the field, contiguous to the border which divides the West Panhandle field from the East Panhandle field, there is a depression in the range. Extending in a southeasterly direction from the island-shaped area, which has been described as being a barren gas area, and contiguous to the border between the West Panhandle field and the East Panhandle field, this axis is subject to considerable deviation, due to the existence of local lows and highs in that area. By local lows and highs I mean areas of locally high and low structural position. Whether they are a series of small axes or not, it is hard to define a big definite axis. In a general way, the axis of this buried mountain range would extend southeastward from the barren area described near the boundary between the east and west fields to a little east of the town of Shamrock in Wheeler County. At that point we are near the borders of the field and it is hard to follow it any farther. Also, this high part of the axis of the field has in general a higher portion extending northward from the center of Potter County through about the central part of Moore County; also a square running northwestward from Potter County, extending into Hartley County. The axis plunges downward into Hartley County, and downward into Moore County, although in the north central part of Moore County is an area where the axis is pretty flat; but near the edges of the field, in the oil area, there is a definitely different formation shown both to the north and to the northwest.

Cross-Examination by Mr. Booth.

Counsel inquires whether from my working papers with reference to the 470,000,000 MCF figure on page 2 of Exhibit 28, it could be divided up by years. There is no pos-

sible way in which anybody could figure out how to divide it by years.

(EXHIBIT NO. 20 for identification, offered and received in evidence without objection.)

159 R. D. PARKER, a witness for defendants, testified as follows:

Direct Examination by Mr. Morgan.

(May 29, 1939)

My name is R. D. Parker. I live in Austin, Texas. I am 61 years of age. I am a consulting engineer. The firm name is Parker, Foran, Knode & Boatright. I have been a consulting engineer since June, 1934.

From 1909 until June, 1934, about twenty-five years, I was connected with the Railroad Commission of Texas.

I graduated in civil engineering from the University of Texas in 1898. Following my graduation I engaged in various lines of work mainly in railroad location, construction, maintenance and operation. After I left the university I worked with the United States Geological Survey for a short time, doing mapping work. Following that I was engaged with several locating parties for proposed lines of railroad in the State of Texas, and for about three years I was connected with the construction department of a line in Texas that is a subsidiary of the Missouri Pacific system. The principal work during that time was the construction of about 300 miles of railroad in Texas, with which I was connected, beginning in field work, location and construction, and finally acting as principal assistant to the chief engineer, and doing office work, supervising the making of estimates, design of structures, and work of that character. However, prior to my connection with this construction work, I was called back to the University of Texas for a year as instructor in civil engineering.

Following the connection I mentioned with the Missouri Pacific system, I was employed by the Southern Pacific system on one of its lines in Texas as office and resident engineer, which involved the control and management of all construction work and maintenance of way, bridges and buildings. That continued until 1909, when I was made chief engineer of the Railroad Commission, and I was engaged

there principally in appraisal work for the basis of the issuance of securities by railroads in Texas under what is known as the stock and bond law. In addition to those duties, I advised counsel for the Commission, made investigations and aided generally in the administration of the laws controlling railroads, the matters of rates and service, my work being principally advising the Commission on operating matters under their jurisdiction, and I was engaged in several of their rate cases, some of them before the Interstate Commerce Commission and some before the State courts.

This work with the Railroad Commission continued until 1920, when I was placed in the Oil and Gas Division in charge of a subdivision known as the gas utilities division of the oil and gas department. That was organized after the enactment of the law which gave the Railroad Com-
160 mission jurisdiction over public utilities engaged in the service of natural gas, which involved, of course, the matter of transportation and distribution and rates and service. Following that engagement was made chief supervisor of the Oil and Gas Division in June, 1926. I was head of the division which had control of the conservation of oil and gas, the making of rules and regulations governing the drilling of wells for the production of oil and gas, the transportation of oil and gas, and the production, and, in later years, what is known as proration, of oil principally in the beginning, and later on in the production of gas. I continued in that position until I retired from the Commission about eight years later.

I was responsible directly to the Commission as a whole during the time I was chief supervisor of the Oil and Gas Division. Mr. Cottingham served under me and under my direction during a part of the time I served there. I appointed him with the approval of the Commission.

During the period of my service I had occasion to know about the various statutes enacted by the State of Texas looking to the prevention of waste of natural resources, particularly oil and gas, and I had to do with the statutes enacted from time to time dealing with the subject of regulation of production of oil and gas. I don't think there is a statute that has been adopted with which I didn't have something to do. I personally sought to administer those statutes, as chief supervisor of the Oil and Gas Division during the time I held that position.

What is known as the original conservation act was

passed on June 30, 1919, by the 36th Legislature. The position of chief supervisor of the Oil and Gas Department was created by virtue of that statute; but I did not occupy it until 1926. During the interval I was in the employ of the Commission and had occasion to keep advised of what was going on under the direction of the Commission.

I have brought here for the benefit of the Federal Power Commission and the Examiner, and others interested, a brief history of the legislative and regulatory policies of the State of Texas, dealing with the subject of oil and gas production and regulation.

(Objections by Commission Counsel and Counsel for Illinois Commerce Commission overruled.)

Questions by the Examiner.

While with the Commission I was not authorized to issue rules and regulations myself. I advised with the Commission with respect to the issuance of rules and regulations. I held hearings myself and made independent investigations. I was the head of the engineering forces that made investigations in the field, and drew practically every order that was ever issued during my administration fixing rules and regulations, based, of course, upon the hearing of testimony and investigations made by me through the agency of the Commission. I either ascertained the facts myself or ascertained them through sworn testimony or by investigation of agents acting under me.

The orders were drawn by me and adopted by the Commission by signature in the usual procedure that the average regulatory body goes through in adopting orders. I submitted proposed orders to the Commission, which either rejected, accepted or modified it. I should say the ma-
161 jority of the orders were accompanied by my recommendations, based on my views of what the hearing elicited or what I thought was necessary in the premises.

Direct Examination Resumed by Mr. Morgan.

The statutes regulating oil and gas and delegating to the Railroad Commission the duty of enforcing oil and gas regulations are based on Article 16, Section 59-A, which was an amendment to the Constitution of 1876, adopted by the vote of the people on August 21, 1917. That amendment declares that the development of all natural resources

is a public right and duty and provides for the issuance of statutes by the legislature conforming with the constitutional amendment. These are the exact words of the amendment: "The conservation and development of all the natural resources of this state are declared public rights and duties, and the legislature shall pass all such laws as may be appropriate thereto."

I think you will find wherever I have spoken of the statute that it is in part the statute; that what I have to say is quoted verbatim, and wherever a court case is mentioned, excerpts or resumes of the decisions of the court, and if I mention the position of any company in this case in any suit, it is based on detail of the company's pleading.

The first statute in pursuance of that constitutional provision was known as the general conservation law, adopted in 1919. It is contained in the general laws of Texas for 1919, passed by the 37th Legislature, Chapter 155, page 285, and is known as Senate Bill No. 350. The law was designed to protect natural gas and oil reserves against waste.

(Examiner permits line of questioning to proceed with the understanding that neither the Examiner nor any party or the Federal Power Commission is bound by the witness' interpretation of statutes.)

In this statute waste was defined, declared unlawful, and prohibited, and the Railroad Commission of Texas was directed by detailed instruction and authority to make and enforce the rules and regulations to govern the drilling and operation of wells producing crude oil and natural gas in order to prevent waste thereof and to require reports to be made to it for that purpose. It was authorized to employ the necessary personnel to perform the duties imposed on it, and it was authorized to require reports to be made to it and to do all things necessary for the proper performance of its duties. The penalty for the violation of the law and the rules and regulations of the Commission was increased from the amount that had been provided in previous statutes to $1000.00 per day for each day's violation occurred and continued.

This statute was an oil and gas conservation law, and prior to the passage of that statute there were some individual provisions in previous statutes that dealt with natural gas and prevented the waste of same, by direct description, and penalties were provided for violation of the statute. One of them is part of the present law; the original gas statute adopted back in 1899 is the principal stat-

ute that regulates the production of natural gas at the present time. It has been amended numbers of times since, until the original simple article has grown almost into a book of laws.

The Texas statutes were recodified in 1925, and the 162 oil and gas conservation statute enacted in 1919 was carried into the recodified statutes. The recodified statutes omitted penalties for violation of the regulation in regard to prevention of waste of both oil and gas, and an amendment was enacted in 1929 which cured that situation (Objection by Commission counsel to entire line of questioning overruled.) The act I refer to was H. B. 388, effective March 29, 1929.

In the meantime I had become chief supervisor of the Oil and Gas Division. At the time this H. B. 388 was passed, the proration system of conserving the supply of oil and prevention of overproduction came into being. The oil industry had theretofore been highly competitive in all its developments, including production, which accounts in some measure for the improper practices in drilling and production. The operator, especially the one who had small holdings and who went into the business, as a rule, as a speculative venture, sought to realize what he could from his venture and get out. This type of operator was usually shrewd, ruthless and overbearing, and was not disposed to respect the law, and prevented legal control wherever and whenever possible in order that his speculations might pay.

(Objection by Commission counsel to characterizations as improper testimony ignored.)

The general practice in the Panhandle oil and gas field with reference to conserving the production of gas during the period from 1925 to 1929 was that the operators took advantage of the fact that no penalties were provided in the statutes, and practically disobeyed them at will. There was a lapse of four years when the Railroad Commission was without a means of preventing the dissipation of gas. During that period the operators permitted enormous quantities of gas to blow in the air in drilling through upper pay; that is, through these red bands on Mr. Peterson's exhibit, No. 16 I think it is. The oil is below the gas; and they drilled with the hole open through those upper gas formations and let the gas blow, and enormous quantities of gas were wasted in that way and still greater quantities were wasted in attempting to increase the production of oil

by using the gas from the upper strata as gas lift operation, which would naturally increase the flow of the wells. This gas was let into the well bore in a number of different ways. It think it would be a good idea to introduce this exhibit that we have here showing those methods at this time.

(Document entitled "Texas Panhandle—Methods of Completing Various Types of Oil and Gas Wells," marked Exhibit 29 for identification.)

Exhibit 29 is a document which was prepared by me. It is a diagramatic cross section of the Panhandle field at the oil-water contact plane and the oil-gas contact plane; that is, in that region of the field where those planes exist, which is on the northeast flank of the structure in the oil producing area. It is merely typical and is merely used for illustrative purposes. It is not drawn to scale, but is purely diagramatic.

By that I mean there are wells drilled in situations portrayed on that document which are completed in the formations as portrayed there, though it is not stated that any particular well is represented by what is before us on that document.

At the top of the drawing, which is labeled "Texas Panhandle, Methods of Completing Various Types of Oil and Gas Wells," is an irregular line on which is shown some little derricks. They represent the surface of the
163 ground. A little ways below that are some perpendicular lines running down to a line which is marked by an open space, below which is another horizontal line. Those lines represent wells, the bottoms of which are represented by the diagram below which is colored. The open space between the first and second heavy horizontal lines, reading from the top, is merely a break in the continuity of the well indications to show that there is a break in the scale and a break in the indications, and the bottom portion of it is diagramatic, whereas the top part is nearer to scale.

The area below the lower of the two horizontal lines typifies what is known as the big lime, or it runs through the big lime where the oil and gas formations exist, where you have porosity that carries oil and gas.

The top of the dolomite is the first line running or dipping from the lefthand side of the diagram to the righthand side above the yellow band. It is the first heavy black line running in a declining direction from the left-

hand side of the map or drawing to the east side and above the upper yellow band. The series of yellow bands are the porous spaces that carry gas down to the gas-oil contact line which has been mentioned. The gas-oil contact line is designated as the division line between the black indication of oil and the yellow indication of gas. Down below the yellow on each formation is black coloring, which typifies the oil producing part of the horizon down to the water level. The water level begins at the line between the black indication and the blue indication. In other words, coming down the structure or down hill along one of those porous formations we first encounter in the porous formations gas; then after passing out of the portion bearing gas we encounter oil; and then we encounter water, if we go on far enough down the structure.

This is an exaggerated diagramatic representation of the decline of those formations as you go down the structure along the flank of the buried granite mountain range. I drew it along a steep line merely to show the dip in structure. It simplified the matter of the illustration I sought to draw from it. I did not intend by this document to show the slope of the formation, the relative thickness of the formations, or anything else except what I have stated—the different types or manners of completing oil and gas wells that I have found to be prevalent in the Panhandle field.

I learned about these completions through investigations made by agents acting under me. They were revealed in hearings conducted by me, and they were revealed to me in investigations that I made personally, and I observed much of the waste going on in the Panhandle on frequent trips at the time it was going on.

During the period from 1925 or 1926, when the Panhandle gas field came in, down to 1935, there was a limitation upon the use of natural gas for the manufacture of carbon black in the State of Texas. The use of carbon black was prohibited except that only casinghead gas might be burned for carbon black. I administered the provisions 164 of that law. In the early history of the Panhandle field the carbon-black industry came on the scene and began its operations. In the beginning of the development of oil there was no other market for natural gas or casinghead gas; but when gas was produced in sufficient quantities the casinghead gasoline plants came in and utilized large quantities of it, blowing the residue into the air.

Some small quantities were returned for lease purposes, but it was immaterial. In the early history of the field it was possible to strip natural gas and blow the residue into the air if it came from a dry gas well. This was possible up until the time it was prohibited by H. B. 266, which became effective in 1936.

Going back to 1926, under the statute of 1899 the dry gas was required to be shut in until it could be used for light and fuel purposes. That was still the law in 1926 and continued to be the law until the enactment of H. B. 266 in 1936, except that in 1933 another act was passed which legalized the production of dry gas and its stripping. I refer to Senate Bill 92, passed in April, 1933. It authorized the utilization of dry gas for the manufacture of gasoline. It put no restriction on what might be done with the residue after the gasoline was extracted. Prior to the enactment of that statute the source of gas which gasoline plants could use for the purpose of extracting the natural gasoline and popping the residue to the air was from oil wells.

During the early history of the Panhandle the wells were completed in such a manner that the gas was produced out of upper parts of the producing formation, which bore gas in place, by means of oil wells for the purpose of lifting the oil and to supply gasoline plants with gas to manufacture gasoline. It was a profitable operation to take natural gas, whether it came out of an oil well or whether it came out of a gas well, and strip out of it by processing its content of natural gasoline and allow the residue to be popped off in the air. As a matter of fact, the oil operator who had wells in the Panhandle at the time when he could do nothing else with his gas was confronted with a constant temptation to utilize as much gas as he could get hold of for the purpose of this profitable operation of stripping the natural gasoline from it.

Taking a column in black on the righthand side of Exhibit 29 on each side of which are some green looking lines —that column represents an oil well completed in the oil portion of the producing horizon near the oil-gas contact line. It did not encounter any free gas in the bore of the well but it was completed near the contact line between the oil and the gas. By the contact line I mean the plane within the producing horizon which divides the oil production from the gas production. That oil-gas contact line is

usually encountered in the Panhandle approximately 100 feet above sea level.

If a well were completed into the oil producing part of the formation which did not encounter any free gas in the well bore as it was drilled down to the oil bearing part of the formation, but which was near the gas-oil contact line, the result, from a practical operating standpoint, would be that the free gas would break through and be produced with the oil. In this well which we have just described the 165 casting seat is above the oil-gas contact line and the gas can break through on account of the position of the casing seat. The casing seat is shown on this drawing by a red jagged line. It is the bottom of the casing that is cemented between the casing and the walls of the hole. The green coloring represents the walls of the casing.

In some instances we have two strings of casing. One is a producing string and the other is a water shut-off. Where the casing is set at a level above the oil, the gas will break through and find its way to the oil well if the oil well be located near the line of contact between the oil and gas. It was an actual occurrence in the Panhandle that wells were completed into the oil at a place near the gas-oil contact line. In some instances an operator could not complete them anywhere else because of the restriction of his lease on the surface.

There is no way of telling from a longitudinal standpoint in advance of drilling a well just where that contact line is. (Objection by Commission Counsel overruled.) The operator was not always anxious to get away from that contact line when he completed a well back in those days, because he wanted the gas after he got a good market for it, with the limited amount of oil he could produce in that position on the structure. He had a market for casinghead gasoline plant operations. The oil operator manifested his objective by setting his casing high. He was limited by his lease restrictions on the surface as to where he could drill his well and the number of wells he could drill.

The operator could have minimized the danger of free gas getting into the well by setting the casing down into the oil formation so he could get a fluid seal on it where the gas would not break through. The gas will stay on top if the casing is driven through to an oil area below. If an operator decided to shut the gas out, instead of setting the casing in the position represented on column 1 on the righthand side of Exhibit 29, he would set it down inside

the oil formation, and that would minimize the danger of free gas coming in; but as a matter of practice in the Panhandle during the earlier years of my regulation up there, he did not do that. If he wanted to produce gas principally, he set his casing high. If he wanted to produce oil, he would set the casing low in the oil.

Coming over to the next column, reading from the right on the same exhibit, we find the column goes down through two yellow bands and encounters the black band at the point where there is free gas also in the well bore, I can state that wells were completed in that situation in the Panhandle field. The operators of those wells could have adopted the same thing I indicated in connection with the other well to keep the gas out of the well—set the casing down in the oil so as to get a fluid seal on it so the gas could not break through; but it was not always possible to keep the gas out even when that was done. When you drill your well on the oil-gas contact line, it is not long before the oil is exhausted and the gas will break through, even though the casing be set down lower. The oil will soon be pulled out of that part of the formation below the gas and gas will immediately replace it and find its
166 way to the well and be produced out of the oil well, with a little oil coming from the other direction. That was a common occurrence in that field.

Coming over to the third column reading from the right on the same exhibit, I have a column which comes down through the same three yellow bands as that penetrated by the well on the right of it, and on into the band of oil producing formation. You have the same situation there as you had in well No. 2, so far as the casing point is concerned, or the point where you set your casing, in proximity to the oil-gas contact line; but the casing was perforated opposite the gas strata, and that permitted the gas to come in and be produced with the oil, operating practically as a gas lift. The oil field term for perforating the casing under those circumstances was to rip it. The common expression in oil field parlance is that the casing was ripped. The oil operator who owned this well knew just exactly where this yellow band was that had been penetrated by that well from the log of the well, and he ripped the casing by letting a casing perforating tool into it and punching holes in it. That is an oil well tool. They let it down in the oil well to a point immediately within the gas producing band, and by a process of machining holes were

cut into the casing so as to permit the gas to go directly into the well bore.

The advantage the operator got from that was that he produced the gas. In the first place, he got more oil by the introduction of gas and using it as a gas lift, and produced the oil faster and therefore in greater quantities, and he got the advantage of his neighbors so far as the oil production was concerned, and then when the market for gas became available he could sell the gas to casinghead gasoline plants and get the gasoline out of it. When the carbon black plants came along to use the residue, he could get additional revenue out of it.

That was a common practice in the Panhandle. I learned that it was a common practice through the investigations of our agents and through hearings. The fact is, it was common knowledge generally. Nobody hesitated to admit it. It was freely admitted all over the field. . There were no restrictions. The penalty was off and they could produce it without being penalized and they made no bones about it. We were powerless to prevent it while the statute was in that form.

In the first column on the drawing are some yellow spots at irregular intervals up the column. That represents diagrammatically the gas being produced along with the oil. There are more spots of that character in column 2 then in column 1 because in the No. 2 wells you would get a greater quantity of gas, because there was a greater quantity of gas available in the upper gas strata. Over in No. 3 the spots are increased because there is still more gas available there from the gas strata and more gas would come into the casing through the perforations. In other words, I mean by the use of these yellow spots in the black columns to indicate the relative, though not necessarily the exact, proportions in the increase of the production of gas in the particular ways the wells are completed.

167 In column 3 there is a break in the green and a white patch between the end of the green at each of the yellow bands. These indications are made to show rips in the casings. They show the openings made in the casing that permitted direct entry of the gas into the bottom of the well.

I have referred to the use of free gas in the well bore for the purpose of aiding in the production of oil. The

operation of letting gas in as I have described here creates a gas lift in the well and the gas lightens the column of oil and thereby increases the production of the well, causing it to flow up the well bore and out at the head of the casing where the derrick is. When the oil producing part of the formation is perforated, the oil rises in the well bore, and when you get the gas into the casing it increases the rate of the flow of oil up the well bore, and under proper circumstances causes the oil to go on out the wellhead. They call that raising oil by gas lift, instead of installing a pump to raise it. It has exactly the same effect that gas in a bottle of soda pop which is hot has, causing it to run over the top of the bottle. It will cause the oil to go up the well bore and flow out into a tank, just like water will flow out of the top of a bottle when it is charged with gas.

Leaving the first three and coming over to column 4, this represents a well drilled through the upper gas formations and completed as an edge well near the gas-oil contact line, similar to the wells on the drawing to the right, except that you have the gas above the oil in the well we are talking about now, No. 4, whereas you do not in No. 1. You have the same action of gas there by reason of the proximity to the gas-oil contact line of the casing point of the well, and the gas will break through just as it did in the well on the right.

In this well No. 4 they just drilled through the gas formation and left the hole open around the casing. Good practice would have been to cement back through the producing gas formation.

The red serrated area along the bottom of one of these columns represents the cement which is pumped back of the casing. It serves two purposes. It keeps upper water out of the oil formation, and limits, or should limit, the production to one formation, in the case of well No. 4, the oil, and prevents communication between strata. If that well had been completed properly, the cement should have come up on the side of the casing to a point above the two formations colored yellow. That was not always done in the completion of wells down there. In many instances the wells are not cemented at all. By that I mean that there was no cement put around the bottom of the casing at the time it was set. As a result of the failure to set the cement back of the casing and around the bottom of the casing, the upper gas would come in by migrating alongside the casing between the casing and the wall of the hole. It

would come down and join forces with the gas from the lower yellow bands and find its way on down to the bottom of the well, and then it would be produced up the well bore and would be called casinghead gas.

168 I am familiar with the term "casinghead gas" as it is used in the records of the Railroad Commission. Those records during my tenure as chief oil and gas supervisor were kept under my direction. I was there with the Commission for twenty-five years, and I am familiar with the records and with the terms that are used in those records.

(Colloquy between Examiner and Counsel with respect to general objection of Mr. Parker's testimony.)

(May 30, 1939.)

My attention is now called to column 5 on Exhibit 29. That portrays the completion of a gas well in the gas area, and signifies that type of well as distinguished from the type of wells portrayed in columns 2, 3 and 4. It is a well producing dry gas only, as distinguished from the wells producing casinghead gas. That well is represented to traverse three streaks or layers in the formation. The casing is set above the first producing formation. That is the normal and usual way of completing a gas well which produces from more than one formation. The object of setting the casing above the top producing area is so as to take in all of the gas producing horizon, which is the part of the well below the red serrated area which, as I have said, indicates a cementing of the casing. That part of the column below that is an open hole, uncased, so that where it passes through these bands there is nothing between the open hole and the formation which yields the gas. That means that the gas flows freely in the well bore. That is also true of the other two gas bearing formations represented there. That is a representative type of well such as I know has been drilled and completed in the Panhandle. The producing formations were not always confined to three. You will sometimes find more than three bands. This is merely representative or typical and is not intended to represent the conditions in every well.

Gas is produced from each type of well illustrated here. Well No. 5 produces nothing but gas. Well No. 4 immediately next to it produces casinghead gas, which comes partly from the oil and partly from the gas formation. The other three wells do likewise.

During my tenure as chief oil and gas supervisor the words "casinghead gas" as used in the records of the Railroad Commission meant gas produced from the casinghead of an oil well. That definition had nothing to do with the source from which the gas came, as to whether or not it was free gas in the formation or otherwise.

The oil and gas division was the division which I headed, and the records, so far as the Railroad Commission is concerned, in so far as they pertain to oil and gas in any form, were kept in that department under my supervision.

When the casinghead gas reaches the top of a well and comes out of the casinghead at the ground, it is run through a separator on the surface, which is connected to the flow line of the well. A separator is a pressure container or device that is used for the separation of oil and gas. It is a cylindrical pressure container in which the gas collects in the top of the cylinder and the oil settles to
169 the bottom, and the gas is drawn off through a pipe.

If it is vented to the air, it goes out to the air. If it goes to a carbon black plant, it goes through a pipe to that plant. If it goes to a casinghead plant, it is piped from the top of the separator. If water comes out with the oil and gas, it is separated by means of gravitation and drops to the bottom of the separator and can be drawn off. The oil is also drawn off at that point. If there is more or less oil in the water, the oil is carried to a feeding plant which separates the water from the oil.

When this mixture of gas and oil or gas, oil and water first comes from the casinghead into the separator it tends to rearrange itself just as it originally was in the formation by gravitation and separation. The water flows and settles to the bottom. The oil comes next, and on top of that is the gas. The gas is drawn off to the casinghead plant or to the pipeline or to the carbon black plant or is popped off.

My office is four or five blocks from the Railroad Commission's office. I am up at the Railroad Commission's offices at least once a week. I get copies of orders issued by the Commission dealing with the subject of oil and gas. I am on their regular mailing list and get copies of all their orders. I get copies of all orders to keep my files up to date. I want to keep informed of conditions generally in that field. I practice my profession as a consulting petroleum engineer dealing with Texas oil and gas fields. (Objection by Commission's counsel and question unan-

swered.) If an order were issued by the Commission changing the meaning of the term casinghead gas, it would be of information to me. It would have a bearing on my work as a consulting engineer because we do gas testing work.

There are regulations which place a limitation on the use of casinghead gas which would control my advice to my clients. It is necessary for me to keep informed of the rules and regulations of the Commission dealing with the subject of natural gas regulations in order to carry on my practice.

I have engaged in branches of the oil and gas business myself. Our firm has an interest in three plants that separate gasoline from natural gas and return the residue gas to the formation from which it is produced. I keep myself informed concerning all rules and regulations which are promulgated by the Railroad Commission concerning the records which the Commission keeps concerning all types of gas that are produced in the State of Texas. I do that in the interest of my professional work and my personal interest as a part owner of three plants which process gas. I should say four plants. We really have an interest in four plants. Casinghead gas is involved in the processing. We have to report the casinghead gas used. By making a report of the casinghead gas used, I mean we make a report on a regular form for that purpose. (Objections by Commission's counsel and counsel for Illinois Commerce Commission overruled.) I have not heard of any change in the meaning of the term casinghead gas, as used in the records of the Railroad Commission, since I left there. I would be in position to have heard of such a change had one been made, and I am sure I would know of it if such a change had been made.

(Statement by Examiner that he is not to be bound by the witness' testimony on the regulations of the Texas Railroad Commission agreed to by company counsel.)

170 The term "gas-oil ratio" is a general term in common use in the oil and gas fraternity as well as by the Railroad Commission. It means the ratio of the oil to the gas produced from oil wells. The gas-oil ratio is expressed in terms of cubic feet of gas to oil in a barrel. A gas-oil ratio of six means six cubic feet to a barrel, and 6000 would mean 6000 cubic feet of gas to a barrel of oil. In the ordinary acceptation the term has nothing to do with gas in

absorption with the oil or dissolved in the oil. It is established by measurement on the surface of the gas coming from the separator through a meter, and the oil is gauged in the stock tanks on the lease.

Taking well No. 3, reading from the right on Exhibit 29, as an example, the gas coming out through that ripped casing from the oil formation goes into the separator and is measured. The gas-oil ratio of that well would be the number of cubic feet of gas produced per barrel of oil from the well. That quantity of gas is a variable thing. It varies with the wells, and depends on the conditions in the well and the completion of the well. The variance is due to the fact that in the oil area overlaid with gas it varies with the amount of gas that comes into the well from the gas strata. If the casinghead gas or the gas which enters into the gas-oil ratio were confined to the gas which is found in the oil, there would not be a wide variance in the gas-oil ratio in the Texas Panhandle. It would be confined to the gas which is in solution in the oil. There is a field in Texas where there is no free gas in the formation above the oil. The East Texas field is that sort of field and I guess it is in fact the largest field in the world. In that field the entire formation is occupied by oil and the entire formation has gas in solution in the oil. The gas-oil ratio in the East Texas field is 370 cubic feet to the barrel. The initial pressure in that field was 1600 pounds per square inch, as compared with 430 pounds per square inch in the Panhandle. I am talking about the bottom hole pressure. It is 1600 pounds as compared with 471 in the Panhandle.

No public comparison has been made that I know of concerning the oil in the East Texas field which would indicate it to have a higher absorption quality than that in the Texas Panhandle. The Bureau of Mines issued a bulletin on the question of the solubility of East Texas gas and oil. From that bulletin I took this oil-gas ratio which I have used, supplemented by my knowledge of tests which have been made in the field—the East Texas field, the one which I have described here as not containing any free gas. This field is located geographically in four counties in northeast Texas. It is not related by contiguity to the Texas Panhandle. There is no formation connection between that field and the Panhandle and no geological relation between the two. The principal city near the East Texas oil field is the city of Tyler, in the northeastern por-

tion of the State. The Panhandle field is in the northwestern portion of the State in what is known as the Panhandle, near the city of Amarillo. It is about 500 or 600 miles from the East Texas field to the Panhandle field.

I do not have the bulletin of the Bureau of Mines here. I let one of the men in my employ have it this morning here in Chicago; but we can get that reference to it today or tomorrow.

(Colloquy between Examiner and Company counsel with respect to effect of testimony of Mr. Cottingham on evidence relating to Texas Railroad Commission Rules.)

171 The gas-oil ratio in East Texas would not be affected at all if the casing were set higher or if it were set lower, or in any particular position. That is true all over the field. The gas-oil ratio is constant. It does not make any difference where the casting is set, what part of the field, or how the oil is produced, the gas-oil ratio is the same. That is because it is inherent. It is all the gas that the oil will take into solution, and it is all the gas that is in the formation. It would not be possible to take the oil out of the formation without bringing the gas with it. There would be no point in reducing the gas-oil ratio of the gas which comes out with the oil as constituting that gas-oil ratio in absorption with the oil. You could not control it. It is not possible to reduce the gas-oil ratio by the quantity absorbed in a barrel of oil. (Objection by Commission counsel and question unanswered.)

The Commission has issued a general order limiting the gas-oil ratio in Texas to 2000, and exceptions are made in different fields. For many years there was no regulation at all. I do not recall when they first started regulating the gas-oil ratio. As applied to the Panhandle there was an order entered in 1932 limiting the gas-oil ratio to 25,000 cubic feet to the barrel, but the order was never enforced. The order now provides that the gas-oil ratio shall be held as low as possible. I think those are the exact words. While there is no limit now except the definition of gas wells and oil wells, that really does not concern this question of gas-oil ratio that we are talking about.

I have noted in the records and reports of the Railroad Commission that gas-oil ratios in the Panhandle field proper were shown to be 6.1 for the month of April, 1938, and that there were other gas-oil ratios in the same field running higher, an average for the month of 1,350 MCF per barrel of oil, and others having no gas-ratio at all. The

higher gas-oil ratio is probably from a well that is located in the oil area which is overlaid with gas, and the gas over the amount that is in solution evidently came from the upper gas horizon.

Wells having no gas-oil ratio in the field were undoubtedly wells located in the northeastern portion of the oil field which is not overlaid by gas formation—where there is no gas contact. The gas from the upper formation could not get into the well and be produced. It is an inherent gas-oil ratio, based on the solubility of the gas in the oil.

You have pointed out that of the 3411 wells producing oil in the Panhandle proper in the month of April, 1938, 2108 of those wells had gas-oil ratios under 2000 cubic feet, and that those wells produced 44,131 barrels of oil and only 37,369,000 cubic feet of gas, while other wells were making large quantities of gas, the remaining 1303 making approximately 370,000,000 cubic feet of gas. I think the wide discrepancy in the gas-oil ratio in the 2100 wells from which the larger proportion of oil is produced, and that in the 1303 wells from which only a small proportion of the oil but most of the gas is produced, is due to the fact that the gas comes from the upper formations and gets into the wells and is produced with the oil.

172 You have referred to my testimony showing the way wells were completed so as to purposely let into the well bore, either around the lower casing or into the side of the casing by ripping the casing, large quantities of gas in proportion to the quantity of oil produced, and have asked me how much gas was produced in the Texas Panhandle in the early history of the oil production. There was no attempt to conserve the gas at all. There was no market for it at that time and nobody cared whether they wasted it or not. It was especially useful in producing oil because it increased the quantity of oil that could be produced from the formation. That period commenced in 1925 after the discovery of the Borger field, and continued during the early development of the field through 1926, 1927, 1928 and 1929. In 1929 the penalty clause was restored in the conservation law and that had the effect of stopping some of these practices, although some of them continued surreptitiously. (Objection by Commission counsel and question unanswered.)

The first order issued which was calculated to control or reduce the production of gas in connection with the production of oil was issued in December, 1932, and provided

for gas-oil ratios; but prior to that, in 1931, an order was entered which provided for the use of what is called the Miller head, which was a device to reduce and prevent the waste of gas in drilling for oil through the upper gas formation; and the same order provided for proper cementing of the casing upon completion of the well.

The wells drilled in the Texas Panhandle field prior to 1929 were drilled in search of oil. Gas wells would be of no value because there was no market in that area for the gas. The wells drilled in the early days were drilled with cable tools. The well was drilled as an open hole by cable tools and the bit that drills the well was on the end of the tool, suspended on the end of the cable and operated by a continuous pounding of the bit as it turned around in the formation. The early wells were drilled in that way and the cavings or cuttings were taken out by what is called a bailer, which is a device with a valve in the bottom of it let down in the hole, and the cavings were taken out with the water. When that drilling found its way on down 2000 feet to the top of the first gas bearing formation, the gas escaped through the open hole; but they didn't do anything about it. They just let it blow while they drilled on down until they got down to where they hoped to find oil. In the meantime gas was flowing up through the open well.

The Miller head was used in connection with rotary control. The use of standard tools, that is, cable tools, was abandoned several years ago and very few wells are drilled in that way now. The Miller head is a device which acts directly on the principle of pressure control. The wells are brought under pressure control and no gas can escape from the well as it is being drilled. They were required in drilling through the gas formation to use the patented device called the Miller head, which would minimize the escape of gas into the air while they were going on down.

There was no gas-oil ratio regulation until 1932, and that regulation was not enforced. The effect of it was
173 nullified by the issuance on the part of the Commission of stripping permits. By stripping permits I mean that free natural gas was permitted to be used for the extraction of gasoline and the residue blown to the air—that is, the portion of the residue which could not be sold for carbon black or lease purposes. The first permit that came to my knowledge was issued to Hagy, Harrington & Marsh in February, 1933. It was followed up by other permits and they became general all over the Panhandle.

Under these permits production was increased to approximately 1,700,000,000 cubic feet per day and the majority of this was wasted. This was all production to gasoline plants; there was other production at that time to pipelines.

This 1,700,000,000 cubic feet of dry gas was run to the gasoline plants for stripping. The dry gas would yield about .25 of a gallon of gasoline per MCF of gas. After stripping, the residue was popped to the air. The gasoline plants were located in a portion of the field north of approximately the central axis. That is where the source of supply was located. A great deal of the gas that was used came from wells in that area. Having unbridled authority to use it, the gas-oil ratio regulation became immaterial. You could not enforce it because there was a permit standing against it.

I received instructions from the Railroad Commission as to what to do about enforcing the gas-oil ratio regulations they had promulgated in December, 1932. We withdrew the order, or I might express it another way by saying that I instructed the deputy supervisor in that district not to attempt to enforce it. I did that on instructions from the Railroad Commission.

In April, 1933, what was known as the stripping law was passed by the Legislature. This legalized the practice of stripping. In other words, the permits which the Railroad Commission had been issuing since February became legalized as a matter of statute the following April. That statute was on the books until House Bill 266 superseded it in May, 1935. However, H. B. 266 was not effective until the following August. Between February, 1933, and the effective date of H. B. 266 in August, 1935, there was uncontrolled stripping of gas for gasoline. Nothing was done during that period toward regulating the gas-oil ratio of oil wells in the field.

House Bill 266 had the effect of stopping stripping. It defined the different kinds of gas and described how they should be used. Ordinary dry sweet gas, such as the large pipelines produce, could be used for light and fuel purposes only. There were carbon black plants in the area; but the use of dry gas for carbon black plants was prohibited. Sour gas could be used for the manufacture of gasoline and the residue used for the manufacture of carbon black. Sweet gas and sour gas were defined by the statute, and casinghead gas was also defined. The definition of casinghead gas contained in H. B. 266 is gas which is indigenous

to oil formations and is produced with oil. The exact definition is "The term casinghead gas shall mean any gas and/or vapor indigenous to an oil stratum and produced from such stratum with oil."

174 That statute was passed in connection with defining the use to which a particular type of gas could be put. An oil well and a gas well were also defined by that same statute. Section 2 (e) provides that "The term oil well is any well which produces one barrel or more of crude petroleum oil to each one hundred thousand cubic feet of natural gas." My understanding is that an oil well is defined as a well which produces one hundred thousand cubic feet of gas to a barrel of oil. That is the substance of it. That is the dividing line between gas and oil wells. Any well that produces above a ratio of 100,000 cubic feet to one barrel of oil is a gas well; and if it produces more oil to make that quantity, it is an oil well. That is merely a definition of an oil well in order to have a dividing line in the statute so the wells could be classified. It if falls within the definition of an oil well, it is prorated as an oil well. If it falls within the definition of a gas well, it is treated as a gas well in the gas-oil ratio regulations promulgated by the Railroad Commission.

Any well producing 775,000 cubic feet of gas would be an oil well if it produced 7.75 barrels with that amount of gas; and if it is produced with a ratio higher than 100,000 cubic feet to the barrel, it is limited to the 775,000 cubic feet of gas regardless. They were not permitted to produce any more. That is what they call the displacement factor.

If a well produced more gas to the barrel of oil than 100,000 cubic feet, it was permitted to produce only 775,000 cubic feet of gas. That merely resulted in the well's being permitted to produce a certain amount of oil and gas. It was limited to that quantity.

I remember the first gas-oil ratio regulation following the enactment of H. B. 266 when the stripping of gas was no longer legal in the Panhandle of Texas. It was 10,000 at first. Under that regulation, where the gas-oil ratio was then 10,000, it meant that 10,000 cubic feet of gas could legally be produced to a barrel of oil. If there was a well in the Panhandle which had produced 100 barrels of oil legally under proration and that particular well happened to have a gas-oil ratio of 10,000, which was the maximum permitted gas-oil ratio, the well would be permitted to produce 1,000,000 cubic feet. The effect of this displace-

ment factor on the gas-oil ratio of other wells in the field was to permit any well in the field to produce the amount of gas that the well producing the maximum amount did. In other words, any well in the field under the displacement factor qualification of the gas-oil ratio regulation was permitted to produce a million cubic feet, provided it produced more than ten barrels of oil, and providing that they did not get over the 100,000 limit and get into the definition of a gas well. The practical effect of this on the gas-oil ratio was that it nullified it, and the practical operation was that there was just about one well in the field which was being regulated, and all the rest of them could produce all the gas they could, unless they got over the 100,000 cubic feet per barrel.

They still have that displacement factor qualification to their gas-oil ratio regulation in the Texas Panhandle.
175 The last order issued sometime in January gives the displacement factor as 775,000 cubic feet. That is the order which is still in force and, therefore, any well in the Panhandle can produce 775,000 cubic feet of gas per day in an oil well if it produces as much as 7.75 barrels of oil. If it produces less than 7.75 barrels of oil a day, it can produce, under that displacement factor, 775,000 cubic feet, regardless of how much oil it produces.

During the time I was chief oil and gas supervisor, J. M. McDonald was deputy supervisor in the Texas Panhandle and worked under my direction, making reports to me in his capacity as deputy supervisor. Some of those reports had to do with the subject of gas-oil ratio.

(Document entitled "Table V. Summary of Wells Connected to Casinghead Plants—Classified as to Ratios", marked Exhibit 30 for identification.)

Exhibit 30 is now presented to me. It is a summary of the wells connected to casinghead gas plants classified as to gas-oil ratios. That report was made to me in July, 1932, and at that time I was chief supervisor of the Oil and Gas Division. That report lists 1154 wells. (Objection by Commission counsel to questions on Exhibit 30.) The report has never been published, but it was a report made to me as chief supervisor and is in my files. I have checked the document which I hold in my hand against the original and know that it is accurate copy of an official report made to me in the line of duty by the subordinate who made it. It is a correct copy of a page in that report. Frankly, I do not know how you could get access to the whole report. A

great many of the old records in the Commission's offices have been misplaced. I do not know whether you could get it now at all or not. It was just a report that was made and filed away as reports by staff men are usually filed in a commission's files. I do not have a certified copy of the complete report and do not know whether I have the remainder of the report in my files or not. There was no attempt to extract any portion of the report and withhold the balance of it. I will try to get hold of a copy of that report and make it available to counsel on the other side; but I am not making any promises.

On this report gas-oil ratios are shown in the first column. Those percentages there are merely the percentage relation of the figures in the preceding column for oil, gas and water.

This report was made to me for my information on the very question we are discussing here. It was made in 1932, the year we had the hearings for the purpose of adopting regulations of gas-oil ratios. I do not recall the details of the report. I kept this portion of it because it is the part that I was especially interested in, and was the part I was interested in at that hearing. I believe I can find the original document, although I do not remember the details.

(EXHIBIT 30 for identification was offered and received in evidence over the objection of counsel for the commissions to each of whom the Examiner granted an exception.)

(EXHIBIT 29 for identification was offered and received in evidence over the objection of counsel for the commissions to each of whom the Examiner granted an exception.)

Cross-Examination by Mr. Booth.

I do not recall when I was first retained by Natural Gas Pipeline Company to make this study. I think it was some time last year. I do not recall the month. I have told you about all I can tell you about it—it was some time during last year. I do not recall how long a period I spent in the preparation of my data. I would have to make a guess at it. A memorandum is presented to me dated May 10, 1938.

176 The study which was contained in that report concerned the legislative history of oil regulation and the administration history of it in Texas from the enactment of the first statute. The submission of the report concluded the work that I did for the company last year.

I was next retained by the company when I received a letter from Judge Morgan not over two weeks ago, asking me to be here to attend this case and to testify to what I had done, or rather to testify generally. He did not specify really what I was to testify about. The testimony which I have offered here was not contained in the report which I submitted to him last year.

Cross-Examination by Mr. Slaff.

With respect to the cases in which I have testified, the only rate case I have testified in was the proceeding before the Kansas Public Service Commission involving rates in Kansas City. That was in 1934. I do not recall the style of the case. It involved gas rates. I have a document here that has something to do with the testimony I gave in that case which shows the date of November, 1934. Evidently the proceedings were after that date. It was after I had left the Railroad Commission. I testified on behalf of the Cities Service Company, the company that sells gas in Kansas City. I do not know when that proceeding was terminated. I do not know whether the Commission issued an order. After I participated in it, I paid no more attention to it.

The subjects covered by me in my testimony concerned the question of the inclusion of stand-by gas reserves in the rate base. I accepted the reserves of Cotner & Crum that have been discussed in this proceeding as representative of the reserves in the Texas Panhandle field at that time. I accepted that report as the report of two reputable geologists and as the report that was sponsored by the American Association of Petroleum Geologists, and I regarded it as authentic. I have not testified in any other rate case since that time. I was there only a day, and that included both direct and cross-examination. I did not return at any other time.

I do not recall that I have testified in any other rate cases. I have testified in the District Courts in the State of Texas in cases involving oil and gas or involving regulations made by the Railroad Commission. Without attempting to be exact, I would say that I have testified in a hundred cases in the past five years since I left the Commission. Before I left the Commission I participated in a number of cases. I was present in practically all of the

important cases that related to the Commission's activities. I was in no private cases at all.

The cases in which I have testified since I left the Commission involved the regulations of the Railroad Commission largely, as related to oil properties, the production of oil, the estimation of oil reserves, and things of that sort. A number of those cases went to the State appellate courts; but I do not think any of them went to the United States Supreme Court. I could not say how many of them
177 went beyond the court of first jurisdiction in Texas; possibly 10% of them did. I would have to go to the Supreme Court records, because I had nothing to do with the cases after they were tried in the trial courts. In those cases I was representing different people. I might and might not be apprised of the fact when an appeal was taken. Generally I would not be. I had no interest in them at all after my testimony. If they involved any question or principle that I thought unusual, I would probably inquire about it, and I get a regular flash service from the State House Reporter that gives all important orders of the full Legislature and of the Commission. It goes over my desk every morning. I follow that with the same degree of care that I follow other stuff that I get; but I do not charge my memory with the details of those cases. If it is an important case it would be mentioned in the service I get across my desk every day; but if it is unimportant it would not. The service I get does not cover all the appellate court decisions. It just picks out particular ones. I think the name of that service is State House Reporter.

I could go through my files and pick out my record of the cases in which I have testified during the last five years, and then go to the Court of Civil Appeals and find out what their records are, and I could go to the Supreme Court and search them out. I don't know how long it would take to get a list of the cases in which I have testified during the last five years. It would take several weeks because of the detail I would have to go through to find out which of them had been appealed; but it would not take long just to make up a list of the cases in which I have testified—probably a day.

In my duties with the Commission and in my capacity as consulting engineer since I left the Commission, I think I have been in print only once. That was in three or four issues of the Oil Weekly in Denver in 1934, on the questions we have been discussing here, waste of gas in the Pan-

handle. That was while I was still with the Commission. (Commission Counsel appealed to the Examiner to instruct the witness not to make gratuitous remarks.)

I will within a week make up a list of the cases in which I have testified during the last five or six years and send it to the Examiner or the Federal Power Commission. All of them are Rule 37 cases relating to permits to drill wells in Texas. Generally speaking, I have a complete record of the cases in which I have testified. I can prepare that list within the next ten days or two weeks.

Redirect Examination by Mr. Morgan.

I testified in a case known as Peoples Petroleum Company vs. Railroad Commission, which is a reported case by a three-judge Federal Court in Texas. That was before I left the Commission. I also testified in the Consolidated case which went to the Supreme Court. I did testify in many cases when I was head of the Oil and Gas Division of the Railroad Commission. I attended court and participated in most of the cases in which the Railroad Commission was a party which involved oil and gas regulation; but I did not understand counsel for the Federal Power Commission desired a list of any cases except those in which I have testified since I left the Commission.

178 In my testimony I have mentioned a displacement factor. This qualifies the regulation of the Railroad Commission dealing with the subject of gas-oil ratios. I have checked up on the displacement qualification or displacement factor, and find that any well producing a less amount than 7.75 barrels of oil would produce on the basis of the definition of an oil well 100,000 cubic feet per barrel. A well producing four barrels of oil would be authorized to produce 400,000 cubic feet of gas. In other words, it can produce up to 100,000 cubic feet of gas per barrel of oil provided it does not produce more than 775,000 cubic feet of gas per day. 775,000 cubic feet per day is the maximum amount of gas which can be produced from an oil well in the Panhandle at the present time.

(Company counsel in response to previous request which had been denied now offered all material underlying Peterson testimony for inspection for the purpose of cross-examination.)

179 J. D. THOMPSON, JR., a witness for defendants, testified as follows:

Direct Examination by Mr. Morgan.

(May 30, 1939.)

My name is J. D. Thompson, Jr. I was born in Johnstown, Ohio, January 31, 1891. I live in Amarillo, Texas.

I graduated from Denison University, Granville, Ohio, in 1914. I received the degree of Bachelor of Science, my major subject being geology. This was followed by approximately two years of graduate work at Cornell University at Ithaca, N. Y., at which time I not only studied there but also did some instruction work, assisting in laboratory work and things like that in the field of geology. My graduate work was in geology. I was at Cornell in the years 1914-1915 and 1915-1916.

I left Cornell in the spring of 1916 to take a position as oil and gas geologist for the Empire Gas & Fuel Company. I have been engaged in that line of activity continuously since that time. I was employed by the Empire Gas & Fuel Company for three years, during which time I did work in Ontario, Canada; New York State, Pennsylvania, Ohio, Indiana, Illinois, Kansas, Colorado, Louisiana, Texas and Oklahoma. The kind of work I did for the Empire Gas & Fuel Company during those three years varied considerably. For a while I did what we called detail work, that is, plain table surveys, mapping structural geology. Later I was put on what they call reconnaissance work, in which they sent a man out in advance to look over unknown areas, and if in the course of his study he finds a place that looks like it might be favorable from a structural standpoint he puts in his reconnaissance report and then they send a detail party out to check the geology in detail. I also did subsurface work in Louisiana, with headquarters at Shreveport. I believe I was there about a year in that connection.

At the end of that time, about the spring or summer of 1919, I resigned from the Empire Gas & Fuel Company and took up work for an independent oil man named Leroy Adams, with headquarters at that time at Wichita, Kansas. I did work for him in various parts of the country, mostly detail and reconnaissance work. I stayed with him, I believe, until the spring of 1922.

At that time I took a position with the Gulf Oil Corporation, then called the Gulf Production Company, as district geologist for the Texas Panhandle area, with headquarters in Amarillo, Texas. I was employed by them continuously for seven years, until the summer of 1929. During that time I spent most of my time in Amarillo or in the Amarillo area. I was in the Fort Worth headquarters office for a while, but even when I lived down there I either had actual supervision of work in the Texas Panhandle area or
180 else was there in person, either doing sub-surface work, or for a while I was transferred to the production department and had charge of the completion of wells. This was during the period of great activity there, what we call the boom period of 1926 and 1927. During those years I had charge of the completion of the wells that they drilled in that area. I believe we completed somewhere around 150 wells during that time. I might state that prior to that time, during the early years of my work up there, it was what we call a wildcat field. It was not yet defined, and it was only problematical as to just what the outcome of the exporation work was going to be; but we had special confidence in that field so that we leased something like 200,000 acres of prospective oil and gas lands.

In reply to the inquiry as to the location of the 150 wells, I can name the general area in which we did our operating. We had development work in central Gray County in the general area of the town of Lefors; also south and west of the town of Pampa. We had still further holdings on up in northeastern Carson County and in the extreme north and central portion of Carson County. I might say that that particular area is of interest because it was there that the Gulf Company drilled the discovery oil well of the Panhandle. They had made that discovery, however, before I went up there. We also had a large number of leases in the Borger area of Hutchinson County, as well as a still larger block in the area across the Canadian River from the Borger field, located at a point three or four miles south of where the town of Stinnett was located. The town of Stinnett was not there at the time we started our operations in that county. That about covers our actual development work. I think we had a little more acreage or a few more productive leases in southwestern Hutchinson County. Our spread of acreage of something around 200,000 acres, covered about the full length of the Texas Panhandle field. It was on the northeast flank on the main axis and

on the southwest flank, except they did not get over into southwest Moore County and into Potter County. However, they took not only within the boundaries of the present known field but necessarily took some acreage that later proved to be non-productive, due to its peculiar position.

As to what I had to do with the completion of those wells, I had to take casing points and give instructions as to where the casing was to be run. I also had to be there and observe them where they were drilling into the pay formation and stop them before they went too deep and got into salt water. Those were my two chief duties in that connection.

That was during the years 1926 and 1927. My duties changed to some extent in 1928 and 1929 during the remainder of my tenure with the Gulf Production Company. I still had that kind of work to do occasionally, but I was assigned the job of correlating the sub-surface geology of the Panhandle and of West Texas with the geophysical survey work that they were having done. They had a magnetometer survey made that covered almost the entire area from the north line of the Texas Panhandle clear down into southwest Texas. There had been and were in
181 process of drilling a good many scattered test wells.

It beame necessary for me to study the cuttings of the samples from those wells and the logs from those wells and try to correlate the sub-surface geology with the geophysical picture. I believe that was the work I was engaged in when in 1929 I resigned and opened my own office as a consultant in Amarillo.

Since I opened my office in Amarillo I have been engaged continuously in doing consulting work on geological problems in connection with oil and gas. 95% of my work has been confined to the Texas Panhandle area. My work is rather varied. I make locations for wells, and give advice as to completion of wells. I make quite a large number of reports on the value of properties, particularly in connection with loans for banks. The operators quite frequently need money to carry on their operations and have to borrow money, and the banks take my reports as a basis for estimating the value of the properties to see whether the loans are secure or not. These reports have to do with the geological and structural situation of the particular leases and the prospects of those leases to produce oil or gas.

I have been consulted in connection with the settlement of estate taxes, in connection with appraising for estate or inheritance tax purposes properties located in the Pan-

handle oil and gas field, and once or twice on income tax matters. I have also been consulted by clients who desired to have me give technical testimony in hearings or lawsuits.

I have prepared a list of clients who have consulted me during the last several years in connection with my geological consultant practice. I came up here unexpectedly and was not able to remember all my clients. The list I have prepared is a partial list.

(Document entitled "Partial List of Clients of J. D. Thompson, Jr., Consulting Geologist", marked Exhibit No. 31 for identification.)

Counsel for complainant has commented that the Chicago District Pipeline Company is not mentioned. I was retained by that company to give some evidence up here in 1934. I am sorry I made that omission. I did that work, of course. I will be glad to supplement this list.

(EXHIBIT NO. 31 for identification, offered and received in evidence without objection.)

Cross-Examination Interposed by Mr. Slaff.

My first client named is stated as the First National Bank, Amarillo, Texas, and in parentheses "Earl Fuqua." He is president of that bank and I have done work for the bank and for him personally. Another one is William H. Bush Estate, Amarillo, Texas, and under that in parentheses is "Chicago." That means the estate has a representative both in Amarillo and in Chicago. Another one is Turman Oil Company, Tulsa, Oklahoma, and then in parentheses under that "International Petroleum Corporation." I believe the name has been changed from Turman Oil Company to International Petroleum Corporation, but I am not absolutely sure about that.

182 *Direct Examination Resumed by Mr. Morgan.*

In order to carry on my business I must keep an up-to-date file on all the development activities. I must obtain copies of the logs in particular areas that I am especially interested in. I must look over samples of the well cuttings, and in general keep up with the developments of the field, keep my files up to date and my maps posted.

I have individual county maps of that area and keep
183 the wells spotted on them as frequently as I am able

to, and I do a very fair job of keeping up with the field, of necessity.

I have access to other geological records in addition to the records and information assembled and kept in my own office. When I left the Gulf Production Company they were so kind as to let me have a copy of all the information that I needed or wanted from their files. That included information on all the development work up to that time, all the logs, and I keep a card record. I take a log, transfer the essential data from the well log on to a card and stick it in my card file, alphabetically arranged, so that it is ready for instant reference. Since I left the Gulf Company I have been a welcome visitor in all the offices of the major oil companies up there, particularly the Gulf Company. I have access to their geological information, particularly their tremendous collection of well cuttings. I don't know how many hundred thousand samples of well cuttings they have.

These samples are taken from the well and put in little sacks, and the depths are marked usually every five or ten feet. Then these little cloth bags of samples are brought into headquarters, washed, dried, and put in bottles. The bottles are marked as to depth and arranged in the proper sequence from the top to the bottom of the well, so that one can get a quick picture of the formations that the well penetrated, or can make as close a study of the samples as he may care to do under a microscope.

Those are all accessible to me, partly on the basis of personal friendship; but I do my bit in return for that. Numbers of my clients also drill wells and I make arrangements that they shall save samples of the cuttings properly, mark them properly, and deliver them to the major oil companies for their use; so I am contributing to these collections. It would be too burdensome for me, just a one man organization, to keep these tremendous libraries of stacks full of bottle samples; so that constitutes, you might say, my public library for drill cutting samples.

There is a clearing house, an exchange, for that kind of information maintained in the Panhandle for all these companies. It is located in the Herring Hotel at Amarillo, and I believe it is conducted by a young man named Dwight. I will secure that information.

At the time I went to Amarillo in 1922 there were two oil wells and not over 20 or 25 gas wells. As to whether

they were being produced at that time, I will state there was a rather peculiar situation there. There was no oil pipeline into the Panhandle at that time, and two major companies, the Gulf Company and the Texas Company, had very large leases up there which they had to hold by virtue of production or development. They found it necessary to produce these wells and store the oil. There were years up there when they pumped oil from the wells into the lease tanks and then into large 55,000 barrel tanks.

184 A portion of the 20 or 25 gas wells were being produced by the Amarillo Oil Company, which owned a pipeline from northern Potter County to the town of Amarillo. Nothing was being done with the gas from the other wells except the use to which it was put for lease development purposes. They used it to fire the boilers when they were drilling other wells if the wildcat well they were drilling was not too far away to lay a small pipeline to it. At that time it was not known where the various oil pools were that were afterwards developed up there. We knew we had two oil wells there part way down on the anticlinal structure. We knew that we had salt water further down, and we knew that we had gas on the apex of the structure, and that is a perfect situation for the development of further oil fields.

The two oil wells that I refer to are in Northern Carson County, almost midway along its north line. One belonged to Gulf Production Company and the other to the Texas Company. The 20 or 25 gas wells which had been drilled prior to 1922 were located mostly in the northern part of Potter County, southeastern Moore County or northern Carson County. Most of those wells had been drilled in search of oil. They found no oil, but found gas. There were a few wells drilled for gas, of course, to give supply to those pipelines to the town of Amarillo, where they were actually in search of gas.

At the time I went there and they had those two wells, they knew enough about the underground geology or subsurface geology to indicate that there might be valuable oil deposits in that country. The oil development and oil activity during the next three years after I arrived there in 1922 was exploratory. A large number of test wells were drilled, scattered throughout the area from one end of the field to the other. It became apparent that this was a tremendous anticlinal structure, along the

axis of which you stood a very fine probability of getting gas, and that along the northeast margin of the field there were excellent prospects for oil. Of course there were wells drilled outside the area of production which resulted in dry holes.

By dry hole, I mean that it was barren of oil or gas. Probably all the dry holes contained salt water. It does not mean that they did not have anything in them. They just did not have oil or gas. Regardless of how much water they have, they are still dry holes in the terminology of the oil field. This salt water would be what we call bottom hole water, dip water, which occupies the pay formation down dip from the oil and gas field.

It is my information that by January 1, 1931, there had been a total of 373 dry holes drilled. Most of these dry holes were along the northeast flank. Some of them were in actual oil producing areas where they met up with tight formations and drilled the well too deep into salt water, and due to the fact that there was not sufficient oil in them they were termed abandoned as dry holes. They began to produce oil in sufficient quantities to result in intensive development in the latter part of 1925.

Up to the spring of 1926 the development was con-
185 fined largely to the Borger area in Hutchinson County; the Dial pool north of the Borger area and across the Canadian River from it; some development on the Burnett ranch in the immediate area of the two wells which I have referred to as discovery wells; and in the Lefors area in Gray County.

Several oil pipelines were built into the field and they then started producing oil in considerable quantities. Naturally, this had an effect on drilling. They had a market for the oil, so they started an intensive drilling campaign. I kept up with the drilling operations from that period in the latter part of 1925 or early in 1926, when the intensive development started, on through the remaining years of that development. I had to in connection with the development of the Gulf Company's properties.

A great majority of the wells encountered gas before they drilled into the oil pay. That was the common experience in the field. The streaks or strata of gas bearing formations encountered in the oil wells in the Borger area before the oil level was reached would vary from well to well. Sometimes there would be several gas pay streaks, and sometimes there would be only one or two.

That gas in the upper formations above the oil level would get into the oil wells unless it was cased off. The practice with reference to casing off the gas in those days varied to a considerable extent. A great many operators, wishing to obtain flowing wells, allowed at least a portion or all of the gas they encountered above the oil to come into the well with the oil. Others tried to case off the gas if they could, and then use the gas more conservatively, using what they called a gas flow, in which they injected a small amount of gas into the bottom of the hole and that flushed the oil out. That resulted in a much more scientific and conservative operation and preserved the gas.

The gas was considered important in those years in that it helped them to produce oil and furnished fuel for operations. It had no commercial value other than that, except for small local pipelines into the little towns in the area.

As to the practice with reference to producing gas along with the oil in those fields, the Borger oil field, the Dial field, the Burnett area, the various areas down the flank of the field toward Gray County, and in Gray County, a great deal of gas was produced with the oil. On the whole, I would say that there was very little consistent effort to conserve the gas. Tremendous amounts of it were wasted to the air which could have been saved if proper methods had been put into effect. I would say there was a continuous waste of that sort down to the year 1932. It was rather a public scandal. By the year 1932 the pressure had declined very materially due to the tremendous amount of gas that had been produced. I would like to add one amplification to my previous answer. Coincidental with the development of these oil fields, of course, came this tremendous gas waste that resulted in the development of a tremendous casinghead gasoline industry, accompanied also by the development of the carbon black industry, to which the casinghead gasoline companies sold a portion of their residue gas.

As to what I mean by casinghead gasoline com-
186 panies or casinghead gasoline plants, that is common usage out there, referring to oil wells from whose casinghead, gas was being produced. The gas that came from the casinghead of the oil wells was either popped into the air and wasted, or used for fuel, or piped to the

casinghead gasoline plants. When it was piped to a casinghead gasoline plant, a portion of the residue might go again to field and lease requirements. A good deal of it went to the carbon black industry, and there was still some popping of the gas into the air, the residue, by the casinghead gasoline plants themselves. The casinghead gasoline plants extracted the natural gasoline from the gas. That was their objective, and then they made such disposition as they could of the residue gas. If they could make no disposition of it, they popped it into the air.

There were a great many of those plants built and put in operation in the Panhandle during those early years. The location of the gasoline plants is shown on Exhibit 12 by about half inch black squares. That map is dated July, 1938. The casinghead plants which had been put into operation by the years 1930 and 1931 were in central Wheeler County, central Gray County, northeastern Carson County, and south and south central Hutchinson County. They were situated near the oil fields because that is where they received their supply. They were not scattered all over the gas field because their supply was limited to so-called casinghead gas in the Panhandle.

It is my impression that they were not permitted to use dry gas for the manufacture of carbon black or for the extraction of gasoline in the years 1926 to 1931. I believe there was a statute preventing it. I am not very familiar with the legal history of this industry. (Motion by Commission Counsel to strike last two answers ignored.) I know it was not legal or was not permissible to use anything except casinghead gas in these casinghead plants back in those early days. It was under control by the Railroad Commission and there were regulations against the use of dry gas.

Another reason why the owners of oil wells would desire to produce large quantities of gas from their wells, other than for the utilizing of that gas to lift the oil and make the well flow instead of having to use pumps, was that they received quite a material income from the sale of gas to the gasoline plants. The casinghead plants supplied a very extensive outlet.

I am familiar with Exhibit 21. The condition which had developed by 1932 in that field with reference to the pressures obtaining in the oil fields and in the vicinity of the oil fields, as represented on Exhibit 21, was that areas of low pressure had developed in the oil fields and

had set up a pressure differential between those low pressure areas and the dry sweet gas fields. The pressure losses have continued progressively throughout the years since then. It is my opinion that the reason for that pressure differential, beginning in 1932 and continuing on down to 1938, as reflected by Exhibit 17, is the tremendous withdrawal of gas in the oil fields from the dry gas producing formations.

I am familiar with Exhibit 16. It portrays what I
187 refer to as a typical example of the conditions found in the sub-surface geology of the Texas Panhandle oil and gas field. By typical example I mean that a condition of that kind could and might exist in various places in the Panhandle. Naturally, there is considerable variation in the sub-surface geology from one end of the field to the other; but in general we have, as portrayed here, an oil bearing area down dip to the northeast, and then an area higher up on the structure to the southwest which is productive of gas only. After you leave the axis, or the granite core, and go to the southwest the rock beds start to dip downward, and continue downward, producing gas until the area is reached where salt water is encountered. I call the mountain range an anticlinal structure, and the center of it longitudinally I refer to as an axis. I am not speaking of a map but of the actual location of that buried granite range. It is irregular. We have observed the irregularity of mountains on the surface and we have a somewhat similar effect of sub-surface buried mountains in the Amarillo area.

As to whether there is a uniform southeasterly and northwesterly direction, I will state that, in general, it is a southeast to northwest direction. There will be places where the mountains would be low places, where there will be peaks when you progress northwestward; but about the center of the south line of Moore County there seems to be a change in the direction of the axis, almost due north, to part way up through Moore County, and also a continuation of the northwest axis out into the southern part of Hartley County.

You do not know where the mountain is unless you drill a hole down to it; but there were enough holes drilled to solid granite throughout the field so that we could establish with some degree of certainty where the geologic high peaks of the buried mountains were. If the beds seem to be in an extremely high structural position, you would prob-

ably anticipate a high granite peak. If you encounter granite wash at an exceedingly high spot, it is quite probable if you continue drilling into this a little ways you will get into solid granite. If you run into the top of the big lime at a high point above sea level, reducing it to sea level datum, you have a high datum point in one well, and then if the wells surrounding it, or the wells to the north and south of it, encounter it very much lower, that indicates you are probably on a buried granite peak.

My attention is called to the fact that at the bottom of Exhibit 16 appears a heavy black line, marked at each end "Sea Level." Along that line in a couple of places is the word "Water." By coincidence, it happens that the water table of the field in general flows along at about sea level. There is some variation, depending on the position of the field; but, in general, down around sea level you anticipate encountering water when you drill. If you drilled into the granite mountain, you would not strike water at sea level unless the granite mountain were fissured or cracked and let the water in that way.

By water table I mean the level that the water seeks in the sedimentary beds of the field. The sedimentary beds are the deposits on the top of the granite mountain
188 range, which are denominated, going from the granite mountain range to the top, as lime, red bed, and gypsum. That is what I mean by sedimentary beds—deposited beds.

My attention is called to a thick area between the heavy black line marked "Water" and "Sea Level" and another line just above with the words "Red Bed" several times, extending irregularly across the drawing from near the figure "1000" to a point on the right hand side of the drawing called "Top of Big Lime." That portrays the depth of the Albany formation. That is a geological formation which has been referred to as "Big Lime" by the drillers, and it has become commonly referred to among geologists by the same name. It is a key horizon which is very useful in determining the structural geology of the field. We can determine the position above sea level of that particular key bed and in that way portray the structure of the field.

Immediately underlying that is a series of shales, anhydrites and dolomitic limestone, which vary quite a bit in thickness but I would say on the average are around 300 feet. That is known as the anhydrite series.

Immediately below the anhydrite series is a series of

beds composed almost entirely of brown dolomitic limestone, which is now generally referred to by the public as brown dolomite formation. It is rather difficult for me to describe the brown dolomite as portrayed on Exhibit 16; but it is the area between what is shown as the granite wash formation and a point about halfway up to the top of the big lime. On that cross section it looks like solid brick work. Most of it is quite dolomitic, but it varies in its physical characteristics. Sometimes it is very tight and non-porous, and again it is very porous and permeable.

My attention is called to the red bands or ribbon-like drawings across what I have described as the dolomitic formation. Later on the same bands are colored in green. The colored area represents the porous parts of the formation. What you find in those various portions of the formation typified by colored bands shown on Exhibit 16 depends upon their structural position. Those formations contain either gas or oil or salt water.

The production of gas from the oil fields has continued on down to the present time; but I don't believe there is as much gas being produced in the oil fields today as there was formerly, at the time when that waste was so terrific in the early stages of development. There is not as much gas there now as there was in those days. The pressures are down to 200 pounds and less.

I am familiar with Exhibits 22, 23, 21 and 17. In some portions of the oil fields the pressures are now below 100 pounds. Naturally, there would not be as much gas coming out of the oil fields under those conditions as when the pressure was around 430 pounds.

A am requested to take the pointer and point out on Exhibit 16 the places from which the gas which has 189 resulted in these pressure differentials has come in the formation. On this ideal cross section representing general conditions obtaining in the Panhandle field, it is my opinion that most of the gas produced as casinghead gas has come from the area which is represented by wells Nos. 2 and 3, reading from the right of the cross section. It has come from the upper beds of gas which are encountered before the oil pays were penetrated. They are colored red on the cross section, while the oil pay formations are colored green. Wells Nos. 4 and 5 also portray that same kind of situation.

As to how far it is from where those red bands change color to green bands down to the sea level or water table,

perpendicularly, I would say it varies to some extent, but approximately 150 feet ought to cover that section. That 150 foot thickness above the water level, which is approximately at sea level, up to where the level of the gas and oil contact is, is streaked with alternate beds of porous and non-porous material. If that 150 feet between the water level and the level of the gas-oil contact was in a vertical range, there might be room for 90 feet of porous gas pay; but, as shown by the cuttings, we don't have any such condition as that existing in the oil field. In my opinion, there are no free gas bearing formations down below the level of contact between oil and gas and above the water level.

I don't remember ever to have seen a log portraying any catchment basins or other various regions down in that range of 150 feet which could account for all of the gas or any substantial part of the gas which has been produced in those oil fields or from those oil wells. If a well were drilled into that oil bearing formation and there were any such deposit of gas down there with the oil as that to which Mr. Brown testified—namely, 6,000 cubic feet for each barrel of oil—the gas would flow the oil out of the hole. That condition does not obtain when a well is drilled into that green formation. In the northeast edge of the oil fields, where no gas accompanies the oil, we have only pumping wells. A little further back, where you encounter gas immediately above the oil, it is entirely possible to have flowing wells. It is gas getting in with the oil which causes those wells to flow. I do not mean that it is gas which has been in absorption with the oil, but free gas that occurs above the oil level.

Without referring to the records, I would not want to be absolutely definite as to where the greater part of the oil is now being produced; but it is my impression that more oil is being produced from areas that contain only pumping wells. Some of the old oil pools which have been producing for ten or twelve years are in the process of abandonment. That is due to a large extent to the fact that they have been exhausted of their oil. They have also developed water trouble, due to improper completion of some of the wells, and some of the wells were drilled too deep, which necessarily allowed bottom hole water to get into the formation and damage the surrounding wells in addition to the well where the trouble started.

It is my judgment that only a negligible quantity of the

gas which has been produced from oil wells in the Pan-
190 handle field came out of absorption in the oil. I have seen oil come out of pumping wells where there was no gas accompanying it and about all there was to it was a bad smell. In the other type of wells, where the gas was encountered above the oil, you frequently have a very large production of gas along with the oil.

I would not be able to tell when the gas comes out whether it has been absorbed or not. I just assume that it has been absorbed, if there is no free gas present in the well. I do not see any other source. The absorbed gas would not free itself to any great extent on the way up the well. If it did, I think we would have more gas coming up to the top of those wells in which gas is not encountered in the well bore before oil is reached. It does not seem conceivable to me as a geologist, in the light of my experience, that if this gas, which enters into the gas-oil ratio of wells in the Panhandle, were coming out of absorption in the oil, many of the wells would make no gas at all, according to the Railroad Commission's records, and some would make only a slight bit of gas, while others would be making several million cubic feet per barrel of oil.

I have never seen a high gas-oil ratio well drilled in that part of the field where the gas is not usually encountered in the well as it is being drilled down to the oil pay. The wells with high gas-oil ratios are situated in the area where you encounter free gas in the upper beds before you drill into the oil pay in the lower part of the formation.

You ask if I know of any devices that were used by operators in the Panhandle field to get that free gas from the upper part of the formation into the well bore so that it would come out and be called casinghead gas. I think you refer to the practice of ripping the pipe or else lifting the pipe off the casing seat. When I say pipe I mean casing. I never saw that done. It is against the law. (Objection by Commission counsel.)

Questions by the Examiner.

I am firmly convinced that it was done. I am quite sure that I have advised my clients of that condition in connection with my remunerated services. I don't know that it is of record in anything I have ever written; but that situation is so generally recognized that we all speak about it as something we know to exist. Of my own knowledge, I am

unable to name any one individual well where I know that occurred. (Objection by Commission counsel overruled.)

In the early stages of the history of the field, the overwhelming production of oil was in company with the production of gas. I think that now more oil is being produced unaccompanied by gas than with it. That means by pumping. I can explain that best by referring to Exhibit 23. In the later history of the oil production in this field some very important oil production has been encountered in the area shown uncolored on this map, where these little black spots indicate oil wells. They are in the northeast flank beyond the places where gas is known to exist. It is more a coincidence than anything else that that portion of the field was developed at a later period than the other
191 portion of the field. I think I can prepare myself for cross examination with respect to oil production in the field in the past.

Direct Examination Resumed by Mr. Morgan.

Bearing on my statement that the majority of the oil is now being produced with comparatively small quantities of gas, I am referred by counsel to page 34 of the annual report of the Railroad Commission, dated July, 1938, which is now Exhibit 26. That tabulation indicates that there are some 2108 wells with a gas-oil ratio of 2,000 cubic feet or less, producing 44,131 barrels of oil and 37,369,000 cubic feet of gas. The report shows a total of 3411 oil wells, so there would remain 1303 oil wells which have a gas-oil ratio of more than 2,000 cubic feet per barrel, and from those 1303 wells an oil production of 23,610 barrels is indicated, with a gas production of 375,970,000 cubic feet.

If that gas were coming out of the oil bearing part of the formation, it is not conceivable to me that there would be that variance between the quantity of gas produced per barrel of oil in the 2108 wells shown in the first group and in the other 1303 wells. I do not see how there could possibly be that much gas in the amount of oil indicated. I base that statement on my own experience and observation in the Panhandle field.

I did not prepare Exhibit 16; but I have prepared three cross sections of my own which portray the conditions across the field in three different localities.

(Document entitled "Gas Pay Cross Section A-B, Moore and Potter Counties, Texas", marked Exhibit No. 32 for identification.

Document entitled "Gas Pay Cross Section C-D, Carson and Hutchinson Counties, Texas", marked Exhibit No. 33 for identification.

Document entitled "Gas Pay Cross Section E-F, Carson and Gray Counties, Texas", marked Exhibit No. 34 for identification.

Map entitled "Zones of Productivity, Texas Panhandle", marked Exhibit No. 35 for identification.)

I prepared Exhibit 32. I made the original compilation and it was later drawn up by draftsmen under my direction. It portrays the variability of the occurrence of gas and oil pays in the Panhandle field. It shows a cross section running from north Moore County southward to northern Potter County across the west end of the Texas Panhandle field. The wells are indicated by small circles joined by a narrow line. Each one of those small circles has a name to the right of it, indicating the well represented by that circle.

The cross section in Exhibit 32 is located along the line A-B shown on Exhibit 35, crossing near the western end of the field. It is a broken line. The occasion for the sharp turns or corners is that the line connects the various wells used in the portrayal of Exhibit 32, and necessarily zigzags to some extent on account of the drilling pattern of the field. I tried to get as nearly a north-south line as I could in order to show what would be a typical cross section.

192 The most southerly well on Exhibit 32 is located at point A on Exhibit 35 and the most northerly well at point B.

I have undertaken to represent by the cross section only that portion of the wells where the pay formations were encountered. That was done in order to avoid making such a tremendously large exhibit portraying the total depth of the hole. The wells may or may not be oil wells. I show the total depth to which the well was drilled, but I do not show the upper part of the well.

Going to Exhibit 16, I point out that the portion of the formation portrayed on the cross section is that part in which oil and gas occurs—those occurrences being indicated by the red and green streaks on Exhibit 16. Ex-

hibit 32 also portrays wells that were drilled deeper than sea level.

From the standpoint of vertical distance, the span covered by the cross section below and above sea level ranges from 1850 feet above sea level to 139 feet below sea level. Those wells are spaced along the cross section by scale. In the horizontal scale two inches equal one mile, and in the vertical scale one inch equals 50 feet. The colored portions within the tubes shown across the crosss ection are also drawn to scale.

The source of the information from which these wells were located and from which the porous or producing formations were located was the well logs plus whatever other information I happened to be able to obtain. I could get the location on the ground, the geographical location, from the ownership maps of the field, with which I am familiar.

The picture which is shown on Exhibit 32 is the bottom of the number of wells which are distributed along that cross section or the line which I have pointed out on these two maps. To illustrate, take the well farthest to the left on the cross section. As shown on the cross section, there is 1150 feet at the top and minus 62 feet at the bottom, which makes a total of 1212 feet shown of that particular well. That well is designated as Bivins A-13.

The legends set down in little rectangles in the upper portion of the exhibit indicate the various formations in which gas was encountered and the relative productivity of such formations. Those portions of the legend colored orange represent gas found in the red bed pay formation which has an open flow volume greater than one million cubic feet to one foot drill. That colored yellow shows gas production from the same pay formation which has less than one million cubic feet open flow volume per foot drill. By a foot drill I mean that if an oil pay of ten feet is indicated and it only produced two million cubic feet of gas, it would be colored yellow but if that same ten feet happened to produce 12 to 15 million cubic feet, I would color it orange.

The red and pink indicate brown dolomite pay, the red being the pay where more than one million cubic feet
193 open flow volume per well per foot was encountered, and the pink where it was less than one million cubic feet per foot of pay. The blue indicates those places

where gas was produced from the white line, the dark blue indicating volume of greater than one million cubic feet open flow volume per foot of drill, and the light blue representing that portion where there is less than one million cubic feet open flow volume per foot pay drill. The brown indicates those places where gas was produced from the granite wash pay formation, the dark brown indicating the higher order of pay and the light brown the lower order of pay.

I do not find the same producing capacity even in the same layer or band of productivity in the same well. More gas will be produced, or less gas, immediately above another portion of the formation than immediately below, depending on its porosity and permeability.

The actual conditions encountered in the drilling of those wells are as delineated or represented by this cross section, according to the best of my information.

The figures to the left of the columns indicate the number of thousand cubic feet of gas encountered in the pay formation indicated immediately to the right. The figures to the right of the indicated pay formation give the depth at which the pay was encountered, and it is plus or minus elevation with reference to sea level. The depth figures give the width of pay. At the bottom of the column you will find the letters G.P. and then a figure following. That G.P. means gauge pay. For instance, in the well that I am indicating now, Troutman No. 1-SP., it has a gauge pay of 77 feet, by adding all the pays.

Taking the Harrison No. 1 well, located at point B on the north side of the field in northern Moore County, I presented the bottom portion of the log of this well from about 400 feet above sea level to a total depth of 3510, which is 44 feet above sea level. I might say that these horizontal lines indicate intervals of 50 feet above sea level or below sea level, as the case may be. Sea level is indicated by a line across the cross section marked in various places with the figure zero and marked at each end as being sea level. I did not show more of a particular well bore than that which is portrayed there because, to conserve space, I only showed that portion of the log which occupies a position in the pay formations. There were no pay formations shown by the log between the top of that portion of the well shown there and the top of the ground.

This Harrison No. 1 well encountered a showing of approximately one million cubic feet of gas at a depth of 3195 feet, which is 359 feet above sea level. The pay formation was so extremely thin that it is represented by a very thin line. I presume that the pay formation was less than one foot thick. It was so represented in the log.

This well encountered another show of gas at a depth of 3245 feet, which is 309 feet above sea level. The rest of the formation continued barren down to a depth of 3427 feet, which is 127 feet above sea level. At this
194 point salt water was encountered. The well continued drilling to a depth of 3510 feet, which is 44 feet above sea level. The total yield was estimated at around one million cubic feet of gas per day, and the pay thickness was so small that it was not given any footage.

Passing over to the Robertson No. 1-E well, that is shown on Exhibit 35 to be in the northern part of Moore County at the first break in the line south or below the letter B on that line. It is the first well immediately below the Harrison well which I just discussed, and is about two and a half miles from that well. In this Robertson well a show of gas was encountered at 3230 feet, which is 341 feet above sea level. At a depth of 3300 feet 1,500,000 cubic feet of gas was encountered at an elevation of plus 271 feet above sea level. A further increase in gas was encountered from 3370 to 3394 feet, the sea level elevation being plus 201 plus 177. At this point the well had 5,300,000 cubic feet of gas in it. This was immediately followed by a much better pay formation, where the gas increased to 11,500,000 cubic feet at 3394 to 3400 feet, of plus 177 plus 171. The well continued and was drilled to a depth of 3710 feet, which is 139 feet below sea level, without encountering any more pay formations.

The total pay thickness in that well was 30 feet, and the open flow volume was 11,500,000 cubic feet per day. That well was gauged at frequent intervals while it was being drilled, and the gauges indicated a very abrupt and sharp pick-up of increased gas in the last five feet or the last six feet of pay formation.

The Brumley-Gulf No. 1 well is approximately 1½ miles south of the Robertson No. 1-E well. This well encountered five million cubic feet of gas per day from a pay formation at 2835 to 2840 feet, which is sea level elevation plus 720 and plus 715. From there on down the log indi-

cates continuous pay. I regard the record of that gas pay as being rather questionable. I was not on the well while it was being drilled, and the drilling superintendent said that there were barren spots and then also spots where they picked up large amounts of gas and spots where they picked up smaller amounts. At 2840 to 2980 feet the well encountered 56,000,000 cubic feet of gas per day. By the time it had reached a depth of 3094 feet of the gas had increased t 75,000,000 cubic feet per day. At the time it reached a depth of 3187 cubic feet per open flow volume of the well increased to 100,000,000 cubic feet per day. From there on down the well showed no more gas pay. It was drilled to the total depth of 3557 feet, which is two feet below sea level. It had a total gas pay log of 352 feet, with a total open flow volume of 100,000,000 cubic feet per day. They did not strike water in that well.

The red color merely indicates the fluctuation of the well less than and exceeding one million cubic feet. Since the record was somewhat questionable, I did not know exactly where to put in the rich part of the pay and where to put in the lean part of the pay, and I took this particular symbol to call attention to the fact that the record was questionable.

195 The Robertson No. 1-E well was drilled to a point 139 feet below sea level, and they did not strike water in that well either. You do not get water every time you drill down below sea level. It is variable and depends upon the position of the well in the field and the position of the porous formation which would carry water.

Referring again to Exhibit 16, if the well be drilled so that it encounters the upper green band near the right hand side of the exhibit, down below sea level, you would encounter water provided you still had a porous formation. If the well were drilled out near the edge of Exhibit 16 and had come down through this brick appearing formation, striking sea level, it would not have encountered water, since that formation has no porosity. Whether you get water at sea level depends on whether your bit is in a porous water-bearing formation or one of those tight nonporous formations when you get down to sea level or some point below sea level.

I will be glad to furnish Mr. Booth with logs showing the dates these wells were drilled. The logs would not show the porosity figures. The formation pressures are shown

on that cross section. At the top of the column representing the log you will find the letters R. P., followed by the figure indicating the original rock pressure at the time the well came in. I am quite sure those are the official gauge pressures of the Railroad Commission.

(May 31, 1939)

I have been requested to explain the difference between porosity and permeability. Porosity is the actual void space in a formation; and permeability indicates the ability of the formation to allow gas or fluid to pass through it. You may, for instance, have considerable void space in such formations as volcanic glass, bubble holes, with no connection between those bubbles. It would have high porosity but no permeability. We can only judge the permeability by the ability of the well to produce. It is my impression that the principal factor in the permeability function is porosity. It puts it very well to say that the porosity of this building was the space contained in all of the rooms and the halls and the corridors, while permeability would be based on the doors and the windows.

There is a figure at the head of each of the columns showing the open flow volume as a certain amount in MCF, but that does not conform to the total of the figures along the left-hand side of the column, and I am requested to explain this discrepancy. Taking well No. 4 of Texoma, on Exhibit 34, I show at the bottom that when they completed the well it made a test showing that it had an open flow
196 volume of 23,648,000 cubic feet. After they had shut the well in and allowed the pressure to build up, they took a final test and got a slightly higher open flow volume, being 25,400,000 cubic feet. I might add that in other wells shown on these exhibits there is even a greater discrepancy, but that is all due to the fact that the final tests were made after the well had been shot or acidized, and the figures alongside of the line down below are the tests taken while the well was being drilled.

Quite frequently in the Panhandle acidizing is done immediately after the well is drilled. Once in a while it will be some time before they are acidized; but very frequently they will shoot a well with nitroglycerin or acidize it immediately upon completion. As a matter of fact, while the well is being drilled in, or drilled through the sand, they blow it down, and so much gas comes out that the volume is reduced by the time they can take the test. I have fre-

quently noted that a well with a gauge of ten million cubic feet at a given point declines slightly when they drill several feet of non-porous gas pay formation.

On the log of the well indicated as Texoma's Haas No. 1 well on Exhibit 32, you will note different sections of pay marked "Gas Inc." That means "gas increase" which was not sufficient to measure.

Going back to Exhibit 32 and passing over to the Clark Gable No. 1 well, located south of the other two, the fourth well from the top in the legend at the top of the exhibit, this well is shown on Exhibit 35 at the fourth break in the open line that is in the yellow spot at the third turn of the line as you come from B down toward A. That well had a show of gas at a depth of 2860 feet, which was 711 feet above sea level. It then encountered 2,500,000 cubic feet of gas in a pay formation from 2885 to 2890. It encountered another increase in the pay from 2975 to 2990, where it had a total open flow volume of ten million cubic feet.

It was then drilled through a very thick pay formation, on which I am not satisfied that the record was accurate, so I again made the notation that the gas record is questionable. In any case, by the time it had reached a depth of 3135 it had encountered 45,000,000 cubic feet of gas. The open flow volume of 59,000,000 cubic feet is not questionable. Those two final gauges are the gauge tests at the time the well was drilled. After drilling some more non-porous formations the well again encountered an increase of gas from 3225 to 3250. That is from 346 to 321 feet above sea level. It had a total final gauge of 59,000,000 cubic feet. The total depth was 3250 feet. The gas pay formations logged in this well total 190 feet; but I seriously question if they did get that much actual pay formation. I think the record there is faulty again.

As you go along the side of the well and get the MCF you add them up each time—they are cumulative. The significance of the fact that the notation of 45,000 MCF is at an elevation of approximately 510 to 515 feet is just a matter of draftsmanship. It had to be put in there some place in that section and it looked pretty good there, so that is where I put it. There is no significance in the fact that it is about at the middle of the pay area.

197 That well finally settled, when the final gauge was taken, at 59,000,000 cubic feet. Apparently, in making up the log they just put "59," since that was the final

gauge, and they just put that down on the log as what it was at the bottom of the hole.

The next well immediately south of the Clark Gable well is the well known as Phillips Petroleum Company's Clarence No. 1. That is shown on Exhibit 35 in the red colored portion of the exhibit moving south from B, the fourth well from the first. This well encountered a total of eight pay formations, having a total thickness of 105 feet. The final open flow volume test was 23,000,000 cubic feet.

The next well is Texoma's Troutman No. 1-S. P. That is the well shown on Exhibit 35 as the fifth circle from the first circle. It had a total of seven pay zones, with a total thickness of 77 feet, and the initial open flow after completion was 14,000,000 cubic feet. When drilling stopped in this well it had blown down to where it had only 8,590,000 cubic feet. It is possible that this well was acidized or shot. It either rocked from 8,590,000 to 14,000,000 cubic feet or it was treated in some such way as to increase production. It was drilled down to a total depth of 3452 feet, which is 137 feet above sea level.

The additional depth to whiich it was drilled below the last pay formation shown, indicated that it was either in the dolomite or in the white lime below the dolomite. However, they had encountered non-porous, non-paying sections from a depth of 3065 to a total depth of 3452. The formation through which that well was being drilled from the bottom of the last pay zone down to the bottom of the well is a part of the general series in which pay zones might be encountered.

When I said either in the dolomite or in the white lime below the dolomite, I was basing my answer on my knowledge of the field. We can get samples from that well and determine very definitely whether it was brown dolomite or white lime. What I would expect to find would be the upper portion as non-porous, and that it would be tight brown dolomite followed by a series of tight non-porous gray and white limestone. In other words, I know from my own knowledge of the field the kinds of formation encountered in that part of the field, and I know from the drilling portrayed by my sketch that the well was in this series and not in solid granite. The reason they continued drilling that well so deep was that it was rather a small well, and most persons knew there was a possibility of getting additional pay streaks in the white limestone below the brown dolomite.

Coon No. 3-M well is the sixth well from the first shown on Exhibit 35. It would be on the edge of the red zone coming from B toward A, which is about a mile and a half north of that little white area. The pay formation was first encountered at a depth of 2500 feet, where they had a show of gas. That would be 932 feet above sea level. They encountered eight pay zones in that well, with a total thickness of 78 feet, and a total open flow of 10,500,000 cubic feet of gas per day. The last pay was at 2956 feet, and they continued drilling to 3140.

198 The next well of the cross section is Coon No. 1-M, drilled by Texoma. It encountered its first pay at a depth of 2675 feet, which is 715 feet above sea level. It encountered a total of seven pay zones, all of which were comparatively thin. The combined thickness of those seven pay zones was only seventeen feet. It had a final open flow volume capacity of 3,400,000 cubic feet of gas.

The pay in the Coon 3-M well was encountered at a higher level than in the Troutman No. 1-S. P. well to the north and the Coon 1-M to the south. That is one of those places where we had an apparently lenticular pay zone in the vicinity of Coon No. 3 which did not occur in the Troutman No. 1 or in the Coon No. 1 wells. It is represented by one of those little local streaks such as we see on Exhibit 16 in the middle broad column representing a well, some distance above the group of red bands.

The next well, Coon No. 4-M, is approximately 3½ miles southwest of the well we have just been discussing. It is shown on Exhibit 35 as the eighth circle from the first circle. This well encountered seven gas pays. It had a total open flow volume of 19,000,000 cubic feet of gas, with a total pay thickness of 82 feet. It also encountered a show of oil at 3120 feet, which is 354 feet above sea level. However, that oil showing was not in a commercial quantity, and the well was completed as a gas well.

The next well is Texoma's Thompson No. 1-P. It encountered eight pay zones, with a total of 69 feet in thickness and a total final open flow volume of 43,800,000 cubic feet of gas per day. This well drilled through the brown dolomite pay formation and encountered granite wash. They got their pay in the granite wash. The pay produced a show of oil and 1,600,000 cubic feet of gas. This pay was encountered between 3205 and 3210 feet, or from 380 to 375 feet above sea level. Farther down the hole, at a depth of 3349 feet, or 236 feet above sea level, they

again encountered a gas pay, but this time it was in the white limestone formation. They encountered a still further pay at a depth of 3431 feet in connection with the white limestone formation. This well had a total of 69 feet of pay in these various formations.

The oil showing is indicated by the black line drawn horizontally through the well section. It was a lens in the granite wash protruding out in the limestone formation.

The next well, Thompson No. 4, is about 1½ miles southwest of Thompson No. 1. This well had eleven gas pays, with a total thickness of 84 feet. The final open flow volume capacity was 28,000,000 cubic feet of gas per day.

Here again we have gas pays in three different types of formation. The upper part of the pay formation, including five pay zones, was in the brown dolomite. This is followed up in the granite wash at a depth of 3006 feet by a pay in the granite wash. This is followed by a pay in the white limestone formation at a depth of 3019 to 3027 feet. Again it encountered a gas pay at 3238 to 3245 feet in a
199 granite wash formation; another pay at 3263 to 3267 in the white lime formation; and two more pays in the granite wash formation at depths of 3306 to 3312 and 3380 to 3390.

This Thompson No. 4 well is shown on Exhibit 35 as the tenth circle from the first. Several small showings of oil were found in this well in the granite wash pay formations both near the bottom and partly up the well. The first of those showings was at 3006 to 3012 feet. "That was a very small showing. Sometimes these showings amount to only enough to freeze up the tools. When I have a black line in the middle of the indicated pay, that indicates that there is a showing of oil. I think I have made a mistake here in indicating some oil showings, which are in reality gas cross-hatches indicated in my legend on the top of the map. I have made an error in my statement this morning in my description of Thompson No. 1-P well and in my description of Thompson No. 4 well."

There were no actual oil showings in Thompson No. 1-P. There was a showing in Coon No. 4-M at 3100 to 3120 feet, in the dolomite, but it was just a small non-commercial showing.

The next well, Haas No. 1, is shown on Exhibit 35 as the eleventh well from the first. It is 3½ miles south and west of Thompson No. 4. The gas pay was first encountered in this well at a depth of 2840 feet, which is 831 feet above

sea level. It encountered gas in sixteen different pays, some of which were in the upper sands, in the brown dolomite, and the lower ones were either in the granite wash pay formation or the white lime pay formation. The total thickness was 100 feet, with an initial production of 66,700,000 cubic feet of gas per day.

The next well is Johnson No. 1. It is approximately a mile and a half due south of Haas No. 1. It is near the end of the little yellow band shown on Exhibit 35. The first pay was encountered in this well at a depth of 2840 feet, which was 858 feet above sea level. It encountered another small show of gas at 2875 feet. At 2920 it encountered a thick pay formation in the brown dolomite, where the increase seems to be almost continuous to the bottom of the pay at 2990. That is a range of 70 feet. It was almost continuous solid pay, or rather, the logs and gauge tests indicated a gradual increase down to 2965, then a very heavy increase from 2965 to 2990, and then a small increase from 2990 to 2995. It had at that point a total cumulative production of 62,000,000 cubic feet of gas per day. Its final test when it was shut in turned out to be 68,700,000 cubic feet of gas per day from a total pay thickness of 75 feet.

The next well is Canadian River Gas Company's Bivins A-21, approximately two miles southeast of the Johnson No. 1. It is located on Exhibit 35 in a little yellow band to the south of the yellow area in which the last two wells were located. This well encountered its first gas at 2645 feet, which is 1071 feet above sea level. It had a total of eight pay zones, five of which were in the brown dolomite and three of which were in the granite wash. The total pay thickness in this well was 50 feet, and the total final gauge was 54,000,000 cubic feet of gas per day. This well was drilled down to a total depth of 3485 feet. From 3020 to 3485, a distance of 465 feet, it drilled dry non-porous formations.

The next well is Coughlan No. 1, approximately three miles south of Bivins A-21. It is just south of the Pot-
200 ter County line on the broken line between A and B. The pay formation was first encountered in that well at 1780 feet, which is 1816 feet above sea level. This pay formation was in what we term the red bed sands. Near the base of the Permian red beds above the big lime of that area we have local areas which produce gas from the sands along the bottom part of the red beds. That is another of

those local lenses in what we refer on Exhibit 16 as the Cave Series. They have rather thin sandstone, true sandstone, which produces gas. They encountered five different pay zones in the cave formation series, the red bed series, where they had a total of 5,400,000 cubic feet of gas per day. These pay zones ranged from 1780 feet down to 2015 feet. Following that they drilled through a normal thickness, what we call the anhydrite series, and down into the brown dolomite pay formation. The first gas pay encountered in this formation was at 2295 feet. It had thirteen different pay zones between a depth of 2320 feet and 2440 feet. Its final gauge was 24,000,000 cubic feet of gas per day, and the total thickness of gas pay was 46 feet.

As you go out from the last well mentioned toward the edge of the field, the next well is approximately 4½ miles south and west of Coughlan No. 1. It is at a point just above the letter A in the gray band along the edge of the field as shown on Exhibit 35.

We encountered a very deep dip there, plunging off to the south, and the first gas was in one of those red bed sands at a depth of 2300 feet, or 1100 feet above sea level, as compared with 1816 feet above sea level in the Coughlan well, showing a very abrupt dip there on the edge of the field. It encountered two gas pay formations in the red bed series, then six gas pay zones in the brown dolomite formation, and finally a show of oil and water at a depth of 3155 feet, which is 248 feet above sea level. The total open flow volume capacity of this well was 4,000,000 cubic feet per day. The total thickness of the pay formation does not seem to be included here on this exhibit, probably left off by mistake. However, the thinness of the pays is indicated, so that you can form a picture in your own mind of about how much the pay thicknesses would have been. I can check the exhibit and add them up right now. In the first pay zone they had a pay from 2300 to 2318 feet, which is 18 feet of pay. Then in the eight following pays the thickness was not more than one foot each, which would make a total pay thickness for the well of 26 feet. The total open flow volume was 4,000,000 cubic feet per day.

I don't remember whether that well was acidized or shot by nitroglycerin. It is my impression that it was not. I know what we call the gray area as shown on Exhibit 20. They don't do much shooting or acidizing out there because they don't drill many wells there; but I am quite sure that some wells in the area have been acidized.

The fact that a gas show was obtained at a higher elevation in Coon No. 3 well does not mean that it was at a higher structural position. It was just a place where the porous zone was situated. This map in reality does not reflect a structure picture other than at either end of the exhibit. It is quite obvious that those two wells there do occupy a low structural position. The only thing that this cross section shows to one who is not familiar with the 201 field is a range of pay thicknesses, the zones which contain ribbons or bands of pay formation; but I would know that Coughlan No. 1 well, being very high, is probably underlaid by a granite peak.

Counsel asks me to visualize the situation by taking an ordinary tarpaulin or wagon sheet made of heavy cloth, then putting on the table several different objects such as a watermelon and a football, a grapefruit, an orange and a billiard ball, and then putting that tarpaulin on top of that. We would have bumps in it where the larger objects are, just as in the structure in the field we have bumps where the buried granite peaks are located. Between them are the depressions or valleys just like you find if you go out in the hills where there is a granite peak above the ground. You would not find a continuous peak running through the country, but peaks and valleys, some higher than others. When the sedimentary depositions were made, which afterwards came to be known as dolomite, it was spread over the top of all of those things and necessarily had a sloping irregular position with reference to a longitudinal line.

Questions by the Examiner.

The varying thickness of the overlying layer might occasionally be such as to throw one off as to what caused the bumps, if we didn't have a lot of additional data to check up with the one particular problem that we had in mind. When we obtain the log of a well down there, we also collect the logs of the wells around it, and they are of immense help to us in interpreting the true sense of the particular log under consideration.

I interpret the first gas pay in the Coon No. 3-M well to have been a local lens. That is in the brown dolomite. I would say the picture of the brown dolomite reflected on Exhibit 16 is a very fair portrayal of the actual condition.

Where the wells are drilled close enough together and we can obtain samples, we can be fairly sure about correlating

these various pay streaks. I don't remember seeing any model which has attempted to correlate those pay streaks. Of course, I have made a lot of maps of cross sections myself in studying the various problems in the field, but they would go into the waste basket after I got through with them.

Direct Examination Resumed by Mr. Morgan.

Exhibit 33 is captioned "Gas Pay Cross Section C-D, Carson and Hutchinson Counties, Texas." I have the same legend and the same character of information portrayed on that exhibit as on Exhibit 32 for identification. This cross section extends from extreme northwest Hutchinson County southward into northern Carson County along the line indicated on Exhibit 35 marked C to D. It extends in an irregular, zigzag direction from well to well in a general northerly direction to D in northwestern Hutchinson County.

The first well reading from the right of the exhibit is the Otis Phillips No. 1 at the northern end of the cross
202 section. It was drilled by Shell Petroleum Company, and is located in northwestern Hutchinson County at the point B in the gray area portrayed on Exhibit 35.

Of the wells portrayed by Exhibit 32, four were drilled to sea level and within fifty feet of sea level, and two of them were drilled quite a distance below sea level. It sometimes happens that you strike water before you reach sea level. There might be a little porous projection upward that the water might push in and fill up.

Going back to the Shell Petroleum Company's Otis Phillips No. 1 well as shown on Exhibit 33, I will state that 15 feet of pay sand was encountered in that well, for a total production of 2,765,000 cubic feet of gas per day. The pay zones were encountered rather low on the structure. The well was drilled to a point 140 feet above sea level. They got a small non-commercial show of oil in that well at 3204 feet.

Without going through all of the detail with reference to each of the wells shown on this cross section, I will say that each well speaks for itself and is accompanied by data showing the number of pay streaks or zones encountered, the thickness of those zones, the productivity of those zones, and how much gas was initially produced from the well, as did Exhibit 32. Exhibit 33 shows 19 different wells, of

which six were drilled to sea level or below, and three were drilled to within 50 feet of sea level. Several of the wells had showings of oil at various depths but they were non-commercial showings. Sometimes these showings are what they call rainbows—just little rainbows spread out on the slush pit showing there is a little bit of oil near there. When the bailer is run down to pull out the slush from the bottom of the well, or the rotary throws it out in the process of drilling, a rainbow shows up on the tank out there that is known as the slush pit.

Passing to Exhibit 34, which is captioned "Gas Pay Cross-Section E-F, Carson and Gray Counties, Texas," I will state that this cross section has its south end in southern Gray County and its north end in northern Carson County. On Exhibit 35 this cross-section has its south end in southwestern Gray County, where we have the letter E, and continues north and west into northern Carson County, where we find the letter F, as shown on Exhibit 35.

The first well shown on that exhibit on the right hand side is the Magnolia Fee No. 1, located just south of the letter F in northern Carson County. It is near the oil bearing area of the gas field. This well encountered a show of gas at 2730 feet, which is 505 feet above sea level. It encountered another show at 2780 feet, another at 2798 feet, and another at 3115 to 3120 feet, which is 120 to 115 feet above sea level It had a pay thickness of 5 feet in the last showing and the upper shows were probably less than one foot thick each. The well was completed as an oil well with a show of gas. They encountered the oil pay at 3173 to 3193 feet, which is 62 to 42 feet above sea level. It was drilled to a total depth of 3208 feet, which is 27 feet above sea level. I do not know the gas-oil ratio of that well.

203 The next well, going from right to left, is Texoma's Schafer No. 6-S. It is located south and west of the Magnolia Fee well approximately two miles. On Exhibit 35 it is shown at a point just south of the town of Skellytown in Carson County. Eight gas pay zones were encountered in that well, having a total thickness of 50 feet, and the initial potential was 80,500,000 cubic feet of gas per day. No oil was encountered in that well.

The same legends and the same explanations are shown on Exhibit 34 as those contained on Exhibits 32 and 33.

Several of the wells shown on that exhibit had oil showings. The Cities Service No. 1 Stephens well indicates that it had oil pays at 3145 to 3150 feet and 3156 to 3161 feet.

I am under the impression that that was not a commercial oil well; but I would have to refer to my records to be certain whether or not it ever produced any oil.

The Hoerner No. 1 well had three places where the log shows oil was indicated. I do not believe that well produced oil in commercial quantities. For cross-examination I will bring the information as to whether either of those wells produced commercial oil, and will also bring the information as to gas-oil ratios of those wells which produced commercial oil.

Going over to the Wilson No. 1 well shown on the left side of that exhibit, I will state that well is located in southwestern Gray County as shown on Exhibit 35. It is approximately half a mile from the lowest small red area in southern Gray County, and is located in Section 202. In drilling that well they encountered six gas pays, which had a total thickness of 32 feet, and the total yield was 7,000,000 cubic feet per day. The well was drilled to a depth of 3475 feet, which was 200 feet below sea level. No porous formation was encountered below sea level. At a depth of 3232 feet, which is 43 feet above sea level, it encountered water. Above that it encountered two small oil shows.

Questions by the Examiner.

As to the nature of the salt water discovery and whether that is percolating salt water or the basic salt water, I will state that it is what we call bottom hole water that was in the formation. I can remember enough about the circumstances of this well so that I can tell you a little bit of the history of it. Ordinarily after one reaches salt water at a point less than 50 feet above sea level one would stop drilling, but this was in an unexplored area and they thought it worth while to spend a few hundred dollars more to make a depth test there and see if the situation in that area was any different from the situation in the rest of the field. It was an exploratory test in the true sense of the word. They encountered salt water at that particular place and then drilled through impervious formations which did not carry additional salt water. I do not remember whether it was granite wash and could not tell you that without looking at the log. Water is just like oil and gas; it only occurs in the porous parts of the formation and is not continuous through the formation any more than oil or gas.

204 Some of my legends use the words "Show Gas" and others "Gas Increase". A show of gas means a very small amount, and a gas increase means that there may have been a considerable increase but that the increase was not actually gauged at the time it was encountered.

Direct Examination Resumed by Mr. Morgan.

The last well on the left is located on Exhibit 35 at a point just above the letter "E" in "Section 200, Block B-2," in southwestern Gray County. On Exhibit 20 it is at a point in southwestern Gray County in the area colored gray.

That well encountered an estimated 4,000,000 cubic feet of gas in a porous zone at 2757 to 2763 feet, which was 525 to 519 feet above sea level. The well was drilled to a total depth of 3290 feet, which is eight feet below sea level, without encountering any more porous zones which could contain water, oil or gas—that is, the formation was so tight that there was no porous space to be occupied by any of those items. I remember that circumstance from the log and the samples of the drill cuttings which I looked at. The total pay in that well was six feet.

(EXHIBITS NOS. 32, 33 and 34 for identification, offered and received in evidence without objection.)

It is my recollection that Munger No. 1 well, shown on Exhibit 34, was neither acidized nor shot. As a practical proposition, it is not the custom to spend the money necessary to acidize or shoot a well which has only five or six feet of pay formation. Where they have such a small well they just consider it hopeless and abandon it. The shooting or acidizing is usually resorted to in wells which have a substantial pay thickness with a view of opening a larger void immediately beyond the bottom of the well.

I have computed the original reserves in the Texas Panhandle field.

(Document entitled "Natural Gas Reserves, Texas Panhandle," marked Exhibit No. 36 for identification.)

In computing the reserves I employed the porosity pressure method, or perhaps porosity pay thickness would describe it better. My formula was as follows: 43,560, which is the number of square feet in one acre, times 70, which is the average foot pay thickness in the commercial portion of the field, times 20%, which is the average porosity of pay formation in the commercial part of the field, times 471, divided by 16.4. 471 is the average original bottom hole ab-

solute pressure. 16.4 is the pressure base at which the gas was measured. Solving that formula, you obtain a
205 result of 17,514,000 cubic feet of gas. That is the gas reserve per acre at zero pounds absolute in the commercial area of the field. The commercial area in the field I estimate to be 1,035,146 acres. That multiplied by the average per acre reserve gives a total of 18,129,547,000,000 cubic feet at zero absolute. I then gave consideration to what I referred to as the marginal area of the field, which I consider to be very low-grade productivity. I estimate this portion of the field to contain 426,790 acres. To this I assigned a productive value of five million cubic feet per acre average through the marginal area. This would give a total reserve then of 2,133,950,000,000 cubic feet of gas. The total for the entire field from both classifications of acreage is 20,263,497,444,000 at zero pounds absolute reservoir condition.

That is the original reserve at zero pounds absolute. By that I mean every cubic foot of gas in the reserves to begin with. I have corrected those figures to various assumed wellhead abandonment pressures, using (a) zero pounds, (b) 25 pounds, (c) 50 pounds, (d) 75 pounds, and (e) 100 pounds. I applied a recovery factor of 90%. My estimates of the recoverable reserves of the Panhandle field at the various assumed wellhead abandonment pressures mentioned are set out in the first group of figures on page 1 of Exhibit 36.

By the same method I have computed the reserves of gas remaining in the Panhandle field as of January 1, 1939, at the same assumed wellhead abandonment pressures and applying the same recovery factor. My estimates of the recoverable reserves as of the date last mentioned are set out in the second group of figures on page 1 of Exhibit 36.

I have also computed or estimated the original recoverable reserves, applying the same corrections and recovery factor, underlying the acreage which Texoma Natural Gas Company owned as of January 1, 1939, at the same assumed wellhead abandonment pressures. My estimates of those reserves at the various assumed wellhead abandonment pressures are shown in the third or last group of figures on page 1 of Exhibit 36.

I have also computed the recoverable reserves underlying the acreage owned by Texoma Natural Gas Company on January 1, 1939, as of that date, at the same assumed wellhead abandonment pressures, and my estimates are set out

in the upper or first group of figures shown on page 2 of Exhibit 36.

I did not use the same pay thickness and porosity factors in computing Texoma's reserves as those I used in computing the reserves over the commercial part of the whole field. I used the pay thicknesses and porosities which were encountered in Texoma's wells individually. I solved my equations, using the various pay thicknesses and porosities encountered in Texoma's wells. Then in estimating the Texoma acreage reserves where no wells have yet been drilled on the tract, I went over the map, considered each individual tract as a separate unit, and applied what I thought was a fair estimate of the productivity of that particular tract. In arriving at my judgment as to the
206 productivity of the undrilled tracts of Texoma, I gave consideration to the productivity of nearby developed acreage and also to what I knew about the geological situation of each of those areas.

I have undertaken to determine the total quantity of natural gas that has been withdrawn, either through the wells located on the leases or by drainage to other leases, from all of the acreage owned by Texoma as of January 1, 1939, and have ascertained how much gas has been produced from the wells that have been drilled on those same lands.

The total production from Texoma's wells is 284,852,785,000 cubic feet of gas. That includes only the measured gas which has come from those wells. There would have been a small amount of gas wasted while the wells were being drilled. Whatever that quantity of gas is that was produced from those wells and wasted in the process of completing them is included in the quantity which I have stated in my exhibit was lost by drainage, so the word "drainage" is not just exactly accurate as it has been used in the exhibits. It would be a little more accurate to say the gas lost to Texoma's acreage but not produced and measured by them. The discrepancy would be simply the gas lost through wastage in drilling. I can think of no other factor.

I stated that the total amount of recoverable natural gas which I had arrived at was 20,263,497,444 M. C. F. and that was arrived at by adding 18,129,547,000 M. C. F. I did not take 90% of the 20,263,497,444,000 cubic feet in arriving at the original recoverable reserves shown in Exhibit 36. I applied a formula correcting the reserve to wellhead basis and then applied my 90% correction factor. I am sorry I

did not make that clear in my testimony. The difference between the seventeen trillion and the twenty trillion is made up of two things: the correction at the wellhead pressure plus the 90%. I do not have available at this time the figure as to how much of the difference between 20,263,497,444,000 and 17,695,139,321,000 shown in Exhibit 36 is attributable to this correction and how much is attributable to the taking of 90% of the twenty trillion figure. The correction factor which I applied to reduce the reserve from zero absolute to zero wellhead was .97028, and then I took 90% of that result, which gave me the figures shown in the exhibit. In computing this correction factor I used a table of correction factors prepared from a Bureau of Mines formula for purposes of making various computations at various pressures, and that is the factor which applies between 471, which is the reservoir pressure, and 430, which is the wellhead pressure originally.

I arrived at the January 1, 1939, figures, as compared with the original, by subtraction. I subtracted the total withdrawals from the original reserves for the field as a whole. As to where I got the total withdrawal figure, we have been working on those figures down there for years. I have used Mr. Peterson's tabulations in my computations. Those are based on the Crum and Cotner figures plus the subsequent records of the Texas Railroad Commission. They are the same figures which Mr. Brown used, except he stopped them in July, 1938, and I brought them on down to January 1, 1939.

1207 *Questions by the Examiner.*

As to whether I collaborated with Mr. Peterson in making my calculations in so far as using the fundamental method is concerned—that is, his section divisions and his averages and things of that sort, we did not collaborate so far as doing the actual work is concerned. I may state that I have made my own computations as to pay thickness and, of course, all of us have discussed these things down there for years, Mr. Peterson and I and other geologists, and we have had long consultations and discussions, and my adoption of the 70-foot pay thickness is due to work that I have actually performed myself. There has been a good deal of discussion of the porosity factor, and it has become a generally accepted figure.

I have been talking about the whole field. When I made up my estimates for the Texoma acreage, I did it privately,

without consultation with Mr. Peterson, but it happens we both used the same method and arrived at fairly close to the same answers. My variation from him would be a difference of opinion with him on the geology of a certain area or some such thing as that. I think it will be obvious that my answer is so close to the answer obtained by Mr. Peterson that, having investigated the data Mr. Peterson will offer, I scarcely think you will find it necessary to investigate mine.

I used a 70-foot pay thickness for the entire area. Those figures are based on work I did some time ago. I doubt if the supporting data on that figure of 70 feet is even in my office. It is a standard figure. If you don't mind, I will give you a little history of it. In 1932 and 1933 when Victor Cotner made his report, several of us went into the matter quite thoroughly and arrived, if I recollect correctly, at a figure of 66 feet thickness. Since that time there have been 700 additional gas wells drilled, and of that 700 a large majority had more accurate records than the wells which Cotner and others had to work with at the time their estimate was made. In the light of what has happened and the information I have been able to get since that figure was adopted in Cotner's report, I felt it was necessary to raise that figure from 65 or 66 feet up to 70 feet. Those men with whose work I am familiar have also raised that figure. I believe those that I know about use 70 feet. I do not know of anyone who uses over 70 feet.

The porosity figure of 20% is also made up from the combined judgment of a good many men after careful discussion. It was used in the Cotner and Crum report and was very seriously considered by them before the report was published. It is now generally accepted by geologists who make estimates of field reserves in the Texas Panhandle. I do not know of any geologist who uses a different figure as an average for the whole area.

As to my reason for assuming five million cubic feet per acre in the marginal area, I will state to start with that since my marginal area occupied so nearly the same position as that indicated by the gray area on Mr. Peterson's map, Exhibit 20, and the gray area on Exhibit 35, I
208 have not thought it necessary to present what would appear to be almost a duplication in the form of a map. I got together all the well data, well history of wells drilled in that area, both of the dry holes and the producing wells. I considered the log of each of those wells and I was

forced to the conclusion that that was an area of very low productivity. The well data indicated that perhaps there was only two or three million cubic feet per acre available there. However, I was a little bit dissatisfied with that because the data was rather scarce, and I decided I would give that portion of the field a per acre recovery of five million cubic feet on the average in order to take care of possible occurrences later on where a well might be drilled in that marginal area and encounter a larger amount of gas than I would anticipate.

"As to whether the Texas Railroad Commission likewise classified that same gray band as an area of marginal productivity. I am not sure that that is contained in any report of theirs." (Interruption and objection by Commission counsel.)

The figures which I used in calculating the recoverable reserves for the gray area indicated on Exhibit 20 were purely judgment figures, after I had abandoned the idea of using the porosity and thickness considerations in that area. In my Texoma calculations I had break-downs giving me small areas over which I used thickness and porosity and used average well readings. The average pay thickness for Texoma's wells was 79 feet. I did not check for average porosity; but I would expect it to run around 20%. As to my working papers, I will be glad to cooperate with Mr. Brown, of the Federal Power Commission, and give him as much information as I have available here in Chicago, and follow any suggestions he has to offer as to how much I should bring up from Amarillo. The same privilege will be accorded the expert for the Illinois Commerce Commission.

(EXHIBIT NO. 36 for identification, offered and received in evidence without objection.)

Direct Examination by Mr. Morgan Resumed.

I have stated in my computations of the recoverable reserves I assigned to each acre of marginal area five million cubic feet per acre. That area is substantially the same as that assigned to marginal acreage in Exhibit 20 and Exhibit 35. Mr. Peterson is not in accord with my figures as to the per acre content of the marginal acreage. As I remember it, his figures are around two or three million cubic feet per acre. The five million cubic feet which he suggested was in connection with his statement that in the marginal area the

open flow volume of the wells drilled would be five million cubic feet or less.

I did not separate that district into several areas and figure them separately, as Mr. Peterson says he did. After giving consideration to every gas well and every dry hole that had been drilled in the area, I assumed an average of five million cubic feet per acre. I also gave consideration to wells along the edge of the commercial area and noted that quite frequently along the outer edges the well would be small, approaching the results obtained by drilling out in what I call the marginal area. I also gave consideration to some dry holes, purely from a structural standpoint.

Questions by the Examiner.

My working papers do not include a tabulation show-
209 ing the wells which were considered and the effect which I gave to the figures I had on them. I would have to refer to my card file built up from my study of it all, and take each separate card out of the file and present it in that way. My last estimate was made before Christmas, and I have seen no reason to change that estimate for the purposes of my present testimony. For that reason I am quite sure that some of my original tabulations have not been saved to present in orderly form. However, I could refer to my card files and present that detail if desired. I do not have those with me in Chicago; but I can make them available for consultation with the engineers of the Commissions if required.

I have not made any other estimates of the recoverable reserves of the Panhandle which have been saved by me. By that I mean I have not saved the working papers. I do have in my files reserve estimates which have been made in the past and simply revised from time to time to meet changing conditions. Those estimates will be available to the engineers for the Commissions if they wish to see them.

Cross-Examination by Mr. Booth.

I was first employed by Natural Gas Pipeline Company of America and Texoma Natural Gas Company to prepare some data during the winter of 1938. At that time I was directed to prepare a line of testimony similar to that which I have given here. I believe the total time I worked on that study was possibly thirteen months. I was re-engaged in

March of this year. I have made a report based on my work in 1938, and it will be available to the engineers for the Commissions. I do not have it with me in Chicago.

In connection with Exhibit 31, which is a partial list of my clients, you asked me about Chicago District Pipeline Company, and I indicated that it had been unintentionally omitted.

As to other estimates of natural gas reserves which I have made and to which I have testified in any court or commission proceeding I will state that I was employed by Texoma in a case styled *Texoma Natural Gas Company* v. *Terrell*, 59 Fed. (2) 750. I testified there by affidavit, and I believe there was some testimony on reserves. That was in 1932 and it is very difficult for me to recall what points I covered.

I was also employed in 1933 in *Texoma Natural Gas Company* v. *Terrell*, 2 Fed. Supp. 168.

I was also employed as a witness in *Texoma Natural Gas Company* v. *Thompson*, 14 Fed. Supp. 318; 300 U. S. 55, 81 L. E. 510. In this last named case I testified for the Railroad Commission of Texas.

I also testified in a rate case in 1935. It was a case before the Railroad Commission of Texas involving the Red River Gas Company in Amarillo. I don't remember much about my testimony in that case, but I am rather of the
210 impression that I did not cover the subject of reserves.

I was retained in that case by the Red River Gas Company. I assume that case included the Chicago District Pipeline situation.

Referring to Exhibit 31, it is my impression that none of my work for any of the companies indicated there involved presentation of testimony before administrative or public agencies as to the amount of reserves in the Panhandle field. I have been retained in quite a lot of litigation down there; for instance, small oil leases and things of that kind, where I have given testimony on just a portion of the field but not involving testimony on the whole field. It is difficult for me to remember how many of them were heard and how many of them were compromised before they went to trial.

I don't believe I have ever published anything. My name is mentioned in connection with the Cotner and Crum study as one of the geologists who was consulted by Cotner and Crum and as participating in the preparation of that report. I did participate in the preparation of that report.

(Document entitled "Railroad Commission of Texas, Oil and Gas Division, Oil and Gas Docket No. 108" dated December 10, 1933, marked Exhibit No. 37 for identification.)

At this point, counsel for defendants read into the record the last paragraph on page 9 and the last paragraph on page 1 of Exhibit 37.

"Therefore, it is ordered, that effective December 11, 1935, the gas-oil ratio of each well in the field shall be kept as low as possible, and no well producing both oil and gas shall be permitted to produce gas in excess of 10,000 cubic feet per barrel of oil produced unless specially authorized by an order of the Commission to vary therefrom. However, any well which by reason of its location, mode of completion, or necessity for total fluid lift, shall be allowed to produce daily a total volume of gas equivalent to that of any other well producing from the Panhandle field proper, so long as the ratio of gas to oil does not exceed that set by statute. A gas-oil ratio determination shall be made on each well at the time of completion, and at the time of retest."

"The oil wells in the oil pools in the field were, as a general rule, drilled through one or more gas-containing strata before entering the oil-containing stratum, and, in many instances, the wells were so completed as to cause production of gas from the gas strata along with the oil and gas from the oil stratum, with the result that tremendous quantities of gas have been produced with the oil, large portions of it coming from gas-producing strata above the oil-producing strata. This gas was in large part blown into the air, and it is estimated that in excess of two trillion cubic feet of gas produced in this manner has been wasted into the air."

211 Document consisting of certain pages from Schedules of the Railroad Commission of Texas, relating to the production of oil in the Panhandle district of Texas, bearing the following effective dates: the first and second pages of Schedule effective May 20, 1936, and the first page of Schedules effective February 1, 1937, April 1, 1937, May 1, 1937, November 1, 1938, January 1, 1939, and April 1, 1939, marked Exhibit No. 38 for identification.

At this point, counsel for defendants read into the record certain statements appearing in the Schedules constituting Exhibit 38.

Schedule effective May 20, 1936: "Effective May 20,

1936, and until further notice, the displacement factor will be 1,071 M. C. F. per well per day."

Schedule effective February 1, 1937: "Effective February 1, 1937, and until further notice, the displacement factor will be 1,422 M. C. F. per well per day."

Schedule effective April 1, 1937: "Effective April 1, 1937, and until further notice, the displacement factor will be 826 M. D. F. per well per day."

Schedule effective May 1, 1937: "Effective May 1, 1937, and until further notice, the displacement factor will be 1,062 M. C. F. per well per day."

Schedule effective November 1, 1938: "Effective November 1, 1938, and until further notice, the displacement factor will be 775 M. C. F. per well per day."

Schedule effective January 1, 1939: "Effective January 1, 1939, and until further notice, the displacement factor will be 500 M. C. F. per well per day."

Schedule effective April 1, 1939: "Effective April 1, 1939, and until further notice, the displacement factor will be 775 M. C. F. per well per day."

212 C. DON HUGHES, a witness for defendants, testified as follows:

Direct Examination by Mr. Culton.

(May 31, 1939.)

My name is C. Don Hughes. I live in Amarillo, Texas. I was born in 1896. My profession is that of a geologist, and I have practiced that profession for nineteen years.

I received my technical education at the University of Kansas, completing my course in geology in the spring of 1920. I attended that institution during the four year term between 1916 and 1920, with an interruption due to the World War while I was in the service. I did not get a degree. I completed all the courses that could have been credited to me in the major on geology; but by taking extra work during the time I was in school, and doing summer work, I still lacked four hours toward a degree. Those four hours of credit could not have been in geology or any related subject, due to the regulations concerning a major subject. I completed all the work required in geology and other kindred subjects.

Prior to the time I left school I had practical experience as a geologist. During the summer of 1919 I was with the Kansas State Geological Survey doing field work in connection with the subject of sub-surface work. This was done under the direct supervision of Dr. Raymond C. Moore, who at that time was head of the Department of Geology in the University of Kansas and also State Geologist of Kansas.

After completing my school work I went to work immediately for the Empire Gas & Fuel Company and was located at Eldorado, Kansas, as assistant resident geologist in charge of the Greenwood County district. That covered the area of Greenwood County and adjacent areas in central Kansas. I was there until 1922, when I was transferred to Duncan, Oklahoma.

The nature of my work in the Greenwood County district was to make recommendations concerning the acquisition of new leases or the dropping of old leases where it became seen that they were outside the boundary of the developing field. It also consisted in the supervising of the drilling in of oil and gas wells, the recommending of the points at which casing should be set, and the depths to drill in order to get all of the pay formations and still stay out of the usual underlying water formation. My supervisor in that office was F. C. Holl.

After I was transferred to Duncan I became the district geologist in charge of the Duncan district of southwestern Oklahoma, covering all of the oil area of southwestern Oklahoma, which would include the territory west of Medill and northwest of Duncan.

213 That is the area in which the Wichita Mountains are located. While there I had occasion to make a study of those mountains and the character of the formations of the surface there. In addition to the regular work of a district geologist, I had some core drilling which we were doing around the Wichita Mountains. By core drilling I mean that we used a diamond core drill and drilled shallow holes to beds which we considered key beds, or beds that would be reliable enough to work structure from. I can explain this by pointing out on Exhibit 16 an example of where core drilling might be undertaken would be in the region of about the fifth well from the right-hand corner or the right-hand edge of the cross section. Assuming that, as it is exhibited here, that surface does not reveal any beds that are mapable

for structure, and knowing that there is a bed a short distance beneath, as exhibited by the Alibates dolomite in this cross section, we might core drill in that vicinity to find out the altitude of the underlying Alibates dolomite, which we would in this case assume to be a reliable bed for structural mapping. That would be an example of core drilling for structure.

In other words, knowing that a certain bed, having a certain type of formation, was somewhere underneath, I would search that formation, not a producing formation, only for the purpose of getting the type of structure. The depth below the mapable structure at shallow distances to which additional formations underlying would also lie at the same altitude, would vary from place to place. That would be determined according to the locality you are drilling in. I might make it plainer by observing that core drilling was usually resorted to in an area where mapable parts of the surface had dipped under and were still at shallow enough depths to render it advisable to drill for that structural information. Thus on this exhibit, assuming we are drilling over the Amarillo dome to determine the spread, we would use the map of the structure of the Alibates, with the idea that the underlying beds as shown on Exhibit 16 would conform. The Alibates would be indicative of what was going on underneath.

I did not have any superior in my office at Duncan. I was the district geologist in charge of that district. I stayed there until December, 1925. Core drilling was only one part of my general work as district geologist, which included work similar to that I have described in connection with the Greenwood County area, the supervising of drilling in wells, and actually watching the wells drilled to determined the casing points and how deep to drill.

After I left Duncan I had a temporary assignment at Cisco, Texas, still with the Empire Gas & Fuel Company, where I stayed from December, 1925, until February, 1926, when I was transferred to Amarillo, Texas, to open a district office there as its geologist. I was in the continuous employ of the Empire Company from the time I finished school until some time subsequent to the time I reached Amarillo.

My work for the Empire Company as district geologist in Amarillo was similar to what I have described

except, that being a much more active area, we had a great deal more of the same sort of things to do, such as the acquisition of new leases, recommendations for wells on leases we already had or new leases, supervising the drilling of those wells—that is, the drilling in of the 214 wells and the depth to which the wells would be drilled.

During the time I was in Amarillo that area experienced what is usually referred to as an oil boom. It was just starting at the time I was transferred to Amarillo. As I remember it, there had not been over 200 wells drilled in the Panhandle, including all the dry holes, the gas wells, and the few oil wells that were then existing. I think there were less than 200 wells. The oil development taking place at the time I reached Amarillo was principally in the vicinity of Borger in the south central part of Hutchinson County. The older area of the Burnett pool in northern Carson County had been partially developed. It was still relatively new. There was quite a bit of activity in that area, but nothing to compare with the activity at Borger. At that time there had also been a few wells drilled in western Gray County, just west of Lefors.

The Empire Company was in the process of completing a well right west of Pampa, which gave indication that a pool would be opened there. If I remember correctly, there might have been one well in the Magic City area of Wheeler County.

After I reached Amarillo the development speeded up very decidedly. I was present during the drilling in of a number of wells in those various areas. The Empire wells were drilled and completed under my supervision. One well in particular was right at the town of Borger. The town of Borger is on a portion of what was originally our lease. There were other leases, some to the northwest of Borger and some to the southeast, extending on down in our own particular company's activities as far as eastern Gray County. During the operations of the Empire Company in the drilling of those wells I kept in close touch with the operations and the formations in which the wells were being drilled. Of necessity, I kept advised of the conditions that were being found in wells drilled by other operators in the area.

The Borger area had formations above the oil in which free gas was encountered in large quantities, and in

order to drill to the oil formations these gas formations had to be penetrated. The usual procedure was to drill down to what is commonly called the top of the "Big Lime" as indicated on Exhibit 16. After drilling a short distance into that so-called "Big Lime," we then set the casing and drilled on through the gas bearing formation. This resulted in enormous quantities of gas being blown into the air during the drilling. In fact, as a matter of field practice, when a person drove up to a well that was drilled under those conditions, he would observe which direction the wind was coming from and stay on the windward side, so that he would try to diminish the possibility of fire due to the starting of cars, because of backfire and igniting the gas that might be blowing from that well.

On that cross section I can point out the illustrative points where the oil wells drilled around Borger were actually drilled. Illustrative of the Borger type of wells would be the ones shown as Nos. 3, 4 and 5 from the right hand corner of Exhibit 16. In drilling, after 215 we had entered the big lime, we would encounter the top of the gas formation, and as that drilling proceeded the gas would increase with the drilling until finally we were at the bottom of the gas bearing formation, when we would have our maximum amount of gas that was coming from all of the various ribbons as represented in red on Exhibit 16. The oil would be under that.

We have had cases where a well originally completed as an oil well and making no gas, or substantially no gas, would thereafter produce large quantities of gas. Those cases were frequent in the Borger field. From my knowledge of the formations out there, the explanation was that in drilling through the gas formation the common practice during the Borger boom was to seat the pipe when we thought we had got through the entire gas-bearing portion or formation, thereby shutting the gas off before drilling into the oil formation, so we knew by the time we seated the pipe how much gas had been encountered in that well. Then coming back to the usual practice, it was to get what we called a formation shut-off—that is, seating that string of pipe so that it cut off the gas. We depended on this seat in the formation in the holes to shut off the gas. If the shut-off held as we drilled into the oil formation, we would not encounter any appreciable amount of gas. We did encounter the oil, however. In numerous cases the casing seat would break

loose, and here would come all that gas which we had just drilled through, into the hole where the oil was. Since it resulted in a definite aid to oil production in bringing the oil to the surface, it was usually not attempted to be remedied.

If the casing seat were knocked loose accidentally, the same thing would happen as if the casing seat became loose intentionally. I know what is meant by ripping a pipe. It is a procedure of running a tool into the hole, which is in effect a sort of knife, and by the manipulation of this tool the casing would be ripped. If someone should either accidentally or intentionally rip a casing, the immediate effect would be that a great volume of gas would come into the well.

In the early life of the field the practice was not to cement. That practice finally reached a point where a great many of the operators decided they would cement their wells and cement off the upper gas so that it would not come into the hole; but after the practice of cementing became prevalent, the ripping of casing also became prevalent. Even when the pipe was cemented, the cement would not always hold. At that time the usual procedure was to dump some cement in the bottom of the hole if you could. In many cases you had so much gas there that you could not do it. Then the Halliburton method came into existence, in which they pumped cement down against pressure. This was a more efficient method than the other; but it does not always prevent gas from coming into the bottom of the hole.

Questions by the Examiner.

In my opinion the cementing was done as a gesture toward conserving the gas; but it was only a gesture. I really don't know whether it was done as the result of an order of the Railroad Commission or as a get-together of the
216 different companies and operators. As I remember it, the boom took place in 1926, and it was probably in 1927 that cementing became customary.

Direct Examination Resumed by Mr. Culton.

Shortly after the operators started to cement the casing, the split casing practice started. That would have the same effect of letting gas into the hole from the upper formations, as a failure to get a good casing seat.

In the Borger area the gas was largely from what we call the brown dolomite, while the oil was from the immediately underlying gray lime. For all practical purposes, they are all one part of the big lime formation.

The cross section showing the producing formations to be in bands is a correct delineation of the way we found them in the Borger field. The producing portion was in bands or ribbons that are all interconnected, as represented on that cross section; but in the well bore they are separated—usually by a tighter portion of the dolomite or lime or a shaly portion of the dolomite or lime. Since they have no porosity, they do not carry gas or oil or water.

In drilling those wells in the Borger area, after getting into the formations usually referred to as the producing formations, we usually encountered gas somewhere near the top of the dolomite formation in what is shown on the cross section, Exhibit 16, as one of the ribbons or one of the pay streaks or producing zones of the dolomite. After passing through that streak or zone we would encounter tighter portions of the formation, either tighter portions of the dolomite that had no porosity or shaly portions of the dolomite which had no porosity and carried no gas. Then after passing through a band of that character we would frequently find another zone of porous formation which would be gas bearing. There was no definite regularity in the number of these porous formations. Even from one well to the next it was difficult to predict just where those ribbons or zones of pay would be encountered. Between the ribbons you would find tight zones or horizons, in which there was no gas due to lack of porosity.

After passing through the gas ribbons as I have described them, and before reaching the oil area, we would generally find another tight horizon devoid of porosity, and it would be in that type of formation that we would try to seat the pipe—in the hard formation that carried neither gas nor oil—if we wanted to produce oil only; but if we wanted to produce oil and also produce gas from the upper ribbons we would be careless in where we would seat the pipe and how we would seat it, or after having seated it at that point, you might actually pull the pipe up and work it up and down. The effect of this would be to let the gas from the gas bearing formations down into the hole on the inside of the casing with the oil.

You ask whether there were gas-oil contact points in that area where a well drilled into one band would produce both

oil and gas. Occasionally you would encounter a condition where you felt certain you were at one of those
217 contact points, the exact contact, in which the gas immediately above and the oil below could not be cased off; but that situation was an unusual one.

I continued in charge of the development work of the Empire Company in that area until the spring of 1929, when I resigned to go in business for myself. Meanwhile the Empire had drilled under my supervision wells in other pools in addition to those drilled in the Borger pool. They had drilled wells in the field from a point northwest of Borger several miles extending southeast of Borger, in the vicinity of the town shown here on Exhibit 17 as Skellytown, in northeast Carson County, and in western Gray County, west and southwest of Pampa, and in eastern Gray County. Those were oil wells. The conditions I have described in the Borger area would be representative of the other areas I have described.

I am familiar with the Texas Railroad Commission's map and its outline of the field. There is a portion of the area shown thereon which did not have the bands of gas but did have the band of oil which I have just described as being found in the Borger area. That portion shown on Exhibit 17 to the northeast of the colored bands—the area which is uncolored northeast of the colored bands on Exhibit 17—is, I am sure, an exact replica of that same portion as shown on the Railroad Commission map. There the formations have dipped so low that the beds which carry the first porosity are down in the oil table, so that those beds carry oil instead of gas, and you do not find any free gas in the oil or in the areas just described above the oil. I never heard of any casing ripping in that area; but there would be no reason for ripping the casing there because even if the casing were ripped, there would be no gas going in to come out with the oil. The only gas that would come out with the oil in those areas would be the gas which was bubbling out of solution from the oil, which is just a negligible quantity. They get the oil out there by pumping the wells.

Questions by the Examiner.

I said that the uncolored or white area northeast of the colored bands on Exhibit 17 is an exact replica of that same portion as shown on Exhibit 12. I should correct that

by saying that the outline of the field as shown on Exhibit 17 is a replica of the Railroad Commission's outline of the field on their 1937 rock pressure map; and Exhibit 12 is the 1938 rock pressure map and has some changes. I don't know. It is possible that some of those changes are in that area. The white areas just north of the Lefors basin in Gray County on the 1938 Railroad Commission map are areas in which the Railroad Commission finds no free gas above the oil, and are in addition to the white areas outlined on Exhibit 17. There is no gas in appreciable quantities in that area. That area is colored in gray indicating that it contains gas. This is Mr. Peterson's rock pressure map of the field and the area referred to is the Wilcox area. There was gas there when the field was originally brought in, at the point where it is now colored gray. There is an area in that restriction northwest of the Lefors basin which even on Mr. Peterson's map seems to show no rock pressure on any of the wells, so I feel sure there are no gas wells in that area.

218 *Direct Examination Resumed by Mr. Culton.*

During the time I was with the Empire Company I had occasion to make a special investigation of the Panhandle for the purpose of determining whether the gas reserves for pipeline use were available. That investigation was the result of the desire of the Empire Gas & Fuel Company to find a reserve of gas sufficient to justify the construction of a pipeline from Kansas City to the reserve. The development which had been taking place had definitely proven that there were large gas fields in areas adjacent to the Borger area. I recommended to the Empire Company that we acquire the gas rights on the Burnett ranch in north central Carson County. On Exhibit 17 that ranch is a rectangular area 12 miles wide and 14 miles long, which includes all of Block 5, I&GN Survey, and the west two rows of sections of Block 4, I&GN Survey. That recommendation was made in 1926, and the company later acquired gas rights on a substantial portion of the ranch.

I am acquainted with that portion of the ideal cross section, Exhibit 16, marked in green, representing oil. I have never found in any portion of the field in bands of that character any gas except that which I have described as infinitesimal. I have not known of any oil wells drilled in the area marked white inside the field limits, which later

turned into producers of gas in substantial amounts. I have known of that happening in wells drilled immediately southwest of the line—in many of them.

I have an estimate as to the amount of gas contained in solution in the oil in those green bands. That judgment is based on a search for information having a direct bearing on the Panhandle for other purposes, but it resulted in my judgment that there is not to exceed 100 cubic feet of gas per barrel of oil dissolved in the Panhandle oil. That statement is based on a search I made through available information several years ago in connection with an oil proposition and not on observation of natural conditions. The search included going through the literature on the subject, my geological professional bulletins, which are decidedly sparse on the matter; talking with the representatives of the Bureau of Mines at the helium plant at Amarillo, Texas, who keep up with such matters; and finding at the time what I thought was the most up-to-date available literature, and from that putting it together largely by process of elimination. It did not include any definite study or results of solutions of gas in the Panhandle oils.

Questions by the Examiner.

I cannot say what the maximum solubility of the Panhandle oil is. It is my idea that as oil containing gas rises to the mouth of the well, the gas bubbles out after it reaches the surface, and I don't think you could tell by observation how much dissolved gas it had contained at the bottom of the well.

Direct Examination Resumed by Mr. Culton.

It was customary for some of the operators in some of the leases to save, for processing, the gas coming from the wells in that area because that gas is richer in gasoline content, although very small in volume. I have been discussing the uncolored area on Exhibit 17.

219 As I have stated, I resigned my position with the Empire Company about 1929 to go into business for myself at Amarillo, and ever since then I have been practicing my profession as a consulting geologist. I have caused to be made a partial list of the clients I have had during that period of time.

(Document entitled "Partial List of Clients of C. Don Hughes, Consulting Geologist," marked Exhibit No. 39 for identification.)

I have at various times done geological work for each and all of the clients whose names are listed on this exhibit. That work has been of various natures, including the recommending of where to buy leases for the drilling of oil and gas wells, recommendations for the purchase of royalty under oil or gas or prospective oil or gas areas, the drilling in of wells, the making of appraisals for commercial and various uses, including inheritance tax payments and income tax payments, the estimating of reserves of gas, studies having to do with drainage of gas, and various purposes of that nature.

I am a member of the local geological society and of the American Association of Petroleum Geologists. I take the publications of the latter regularly. Our local association meets from time to time and discusses local geological problems. It meets quite regularly through the winter.

(EXHIBIT NO. 39 for identification, offered and received in evidence without objection.)

In my work at Amarillo I have had occasion to familiarize myself with the records of the Railroad Commission of Texas. Most of the records relating to the Panhandle are kept in the office at Pampa, Texas. I have had occasion from time to time to personally handle those records and take data therefrom. I am familiar with their method of keeping records. I have had occasion to investigate the method used by the Railroad Commission in its office of Pampa in keeping track of the amount of gas produced from oil wells in the Panhandle. The information which they have comes to them on what is called the E-H-4 report, made by the companies, showing the lease name and the company name and the well numbers of the leases that produce gas from oil wells. These reports make no distinction between the amount of gas produced from the same band which contains the oil and the gas produced by those same wells from upper bands. It is all run in as one figure so long as it is coming from the oil well. (Objection by Commission counsel.)

Questions by the Examiner:

I know these records from having handled them and having seen and worked with them in the Commission's office after they had been sworn to by the companies and sent to the Railroad Commission. As a part of my profession I am

constantly working with figures of that nature, and on numerous occasions I have had to go through those figures on various portions of the field. I have not done it for every year that they have issued an annual report. I did not do it for 1938. In fact right at the present time, I have not checked the figure. I would not be able to say exactly for what year I did check the figures. There was a time when Mr. Alex Crowell was in charge of that office that we worked together on the annual figures. In some cases he included in his annual reports some figures taken out of my notebooks.

Direct Examination Resumed by Mr. Culton.

There is no other report made to the Commission of the gas produced from oil wells except the E-H-4 report.
220 I know as a matter of course that the gas being reported to the Commission must come to them on this E-H-4 report. That is what it is for. The general instructions from the Commission are to make the report on that form. I have seen the forms, and I think they carry that instruction on the front of each one. (Objections by Commission Counsel to foregoing testimony overruled.) From my familiarity with the reports themselves and the methods used by the Railroad Commission, I would say definitely that they are the forms from which the annual reports are compiled. (Objection by Commission Counsel and question withdrawn.)

I feel sure that the term "oil-gas ratio" has a definite meaning in that region. It is the ratio in MCF per barrel of oil of the amount of gas that an oil well produces while producing its oil. As to whether the source of the gas enters into the definition or whether it is the volume of gas irrespective of its original source, it is the volume irrespective of the source. (Objections by Commission Counsel to above testimony overruled.)

During the time I have been in Amarillo I have spent a great deal of time in studying the gas problems of the Panhandle field, including the amount of gas in there, the amount of drainage, and things of that character. In making that study I have observed that there is a great variance over the field in so far as standard productivity is concerned with respect to the gas area. The potential open flow of the field varies a great deal as shown by the

Railroad Commission on their maps. It varies within the outline of the field and ranges from zero to more than 100 million cubic feet per day.

Exhibit 35 is a map I have caused to be prepared showing the potential production in different portions of the field. By potential or open flow I mean the volume of gas in cubic feet that a gas well will produce in 24 hours.

On Exhibit 35 I have spotted all the gas wells in the Panhandle field. I have made allowance for wells that came in at a time when the pressure had declined by estimating back to what they would have been at virgin rock pressure conditions, so that the map indicates a picture of the conditions that would have obtained had the wells been drilled in those various areas under virgin rock pressure conditions. The potentials or open flows of the wells under those conditions are indicated on the map in numerals.

The areas colored yellow on the map indicate the regions in which the largest gas wells occur, and, as shown by the legend, those are the areas in which an open flow above 40,000,000 cubic feet per day was encountered. The wells scattered throughout the various yellow areas have figures alongside them. Those figures refer to the millions of cubic feet the respective wells will produce. The highest productivity as evidenced from the open flow potential is shown in the areas colored yellow.

The next band is shown in green, and includes wells with open flows ranging from 25 to 40 million cubic feet per day. I used the same method in outlining the green area which I used in outlining the yellow areas.

221 The next band of productivity is the red area, which designates areas in which open flows of 10 to 25 million cubic feet per day are encountered.

The next band is blue, and it indicates areas of open flow of 5 to 10 million cubic feet per day; and the next one, the gray, indicates areas below five million cubic feet per day.

All of those figures relate to potentials based on original pressure. Some of the wells which I have used as control points were not drilled when the area was at virgin pressure. In those wells the open flow was computed back in accordance with the U. S. Bureau of Mines back pressure curves. I did that for the purpose of getting

what would have been virgin open flows on the wells that have come in at declined rock pressures. I might say, however, that the bulk of the map was made up of wells drilled sufficiently early in the life of the field so that that procedure was not necessary.

My attention is called to a blue area down in the heel of this enormous foot with some red areas in it, more or less on the boundary between Carson and Gray Counties. Those red areas are indicated due to the presence of gas wells at those positions which encountered open flows of 21 and 22, and I cannot tell what the other figure is. The line indicating Mr. Thompson's cross section has gone over one of my figures. I didn't color the entire area in red because there are other wells out away from these which encountered volumes of 3 and 4, and out a little farther even some dry holes.

Since the map was prepared I have learned that there is an area where the coloring was based on erroneous information. There is one well over in southeast Hartley County that has come to my attention. I banded it for the gray because it was indicated as a 1.4 million open flow well on the Railroad Commission report of last year with practically virgin rock pressure. I have since learned that that well was approximately a 10 million well when it was first drilled in. In the light of that information, a small blue area should really be colored around that well—just a small blue island covering possibly a quarter section or so.

Exhibit 35 has the same colors as are used on some of the bands on the pressure map, but it is not related to the pressure map at all. It is prepared solely for the purpose of showing the zones of open flow in the field.

If we have two wells with the same pressure and the same thickness of sand, there could be a difference between the productivity of the two tracts. The first observable difference would be evidenced in the size of the well, the open flow potential. The open flow potential is ordinarily regarded as an indicator of the relative productivity of the tracts. This is especially so in the Panhandle. I have had occasion to make a special study of that with respect to the Panhandle for a number of years, and have
222 concluded that there is a direct relationship between open flow and the amount of gas in the area per

acre. This situation would not necessarily apply to every field to the extent that it applies in the Panhandle.

If in the Panhandle you have a well with a potential open flow at virgin pressure of 20 million cubic feet of gas daily, and that well has been completed in a normal way without shooting and without acidizing the volume I would expect to find contained in the formation would be remarkably close to that figure of 20 million, except it would be an expression of the amount of gas per acre rather than of open flow, and would be used on virgin pressure conditions at a 16.4 pounds measurement. My studies have resulted in my reaching the conclusion that the factor of approximately .9 is the exact relationship. In other words, multiplying the volume of daily potential at virgin pressure by .9 gives approximately what I consider the gas in the formation to be per acre.

I have checked that in a great many ways over the past several years. The first checking was an application of the porosity thickness method of computing reserves, which led me to the first observation that the two figures were remarkably close. I reached that conclusion after having watched wells drilled in and observing their thickness and using what I considered the best available information as to porosity, and computing from those thicknesses and porosities the reserve per acre, and then after having done that I observed that the well itself had resulted in a figure almost identical. It was purely a happenstance. It might not happen in another field at all.

When I first discovered that situation I attempted to apply it to areas scattered over the field, and found that it worked remarkably well. The next step in my study of that process was to zone the field and, instead of using two zones as Mr. Cotner and Mr. Crum used in their reports, I went on and zoned the field into further bands, and by applying that relationship and adding up all the answers I arrived at figures that were what I considered reasonable and correct figures for original reserves of the field. I found that my computations checked with those made by other geologists on the acres times thickness. They checked remarkably close. They would not always be the same as to individual portions of the field; but in the final analysis, and in a great many cases in portions of the field, the figures came out fairly good.

It is not true that all the wells are properly drilled and

completed in the field. It would make a difference whether or not a well was completed in a standard condition. For instance, if I accepted as the potential of a well a figure that was the result of acidization or the shooting of a well, it is obvious that that would not be the figure I should use; so in assembling my information I have made careful attempts, and have made the corrections, in order to get the open flows which represented the natural state of the well before acidization or shooting occurred.

I heard Mr. Brown speak of the pressure decline
223 method of determining reserves. I am familiar with that method, and I do not think the method as he applied it could be applied in the Panhandle field. The first reason is that the pressures in the Panhandle are not uniform throughout the field. The pressure decline method, as Mr. Brown used it, by taking a weighted average pressure of the field based on acreage alone, leads to the definite assumption in that application that each and every acre had the same amount of gas in place under it to start with, which we know is not the case. Therefore, that application would not give a correct figure. If the acreage all had the same productivity, the pressure decline method of computing reserves could be applied. It could also be applied if the pressures throughout the field were going down uniformly so that each and every well in the field exhibited the same pressure, even though the amount of gas per acre in place did vary as it does in the Panhandle field.

The only other circumstances under which the pressure decline method could be used, as applied by Mr. Brown, would be that if the field were shut in sufficiently long to allow an equalization of pressures to take place, then that equalized pressure would allow the application of the pressure decline method. In other words, it is necessary to apply the equilibrium pressure factor in using the pressure decline method, after the reservoir has obtained equilibrium; but that has not happened in the Panhandle. The pressure map is all that is needed to show that that situation has not resulted.

It is not the same thing as the equilibrium pressure to refer to the weighted average pressure. In the Panhandle field it is not true because a great deal of the areas which have suffered the sizable pressure declines are areas which originally had much more gas in place to start with than

some of the other areas which still have high pressures. There is not enough gas out in the lean areas to move into these low pressure, originally rich areas, to build the pressure and volume back up to a weighted average pressure, weighted by acreage alone.

Under ideal conditions there would be the same drop per pound in a reservoir where the pressure decline method is used, whether the given volume of gas was taken off in the early part or the latter part of exhaustion. The same production per pound drop would have the same effect on the reservoir pressure at any time during the life of the reservoir.

If the pressure decline method used by Mr. Brown were applied for different periods in the history of the Panhandle, you would not get the same results for those different periods. You would not get the same per pound drop for the different periods.

(June 1, 1939.)

(Document entitled "Railroad Commission of Texas, Annual Report on the Panhandle Oil and Gas Field, July, 1938", substituted as Exhibit No. 26 for identification in lieu of photostat copy of pages 43 to 40, inclusive, thereof.

Exhibit No. 26 for identification, offered and received in evidence over the objection of counsel for each of the two Commissions, to whom the Examiner granted exceptions. But see Examiner's statement as to agreement with Commission Counsel's position at transcript page 1357.)

224 *Direct Examination by Mr. Morgan.*

I have stated that if the proper pressure factor be used in applying the pressure decline method of computing reserves, the withdrawal per pound drop should be the same at any time in the history of the field. In other words, if 337.66 were the proper pressure factor to apply in computing reserves by the pressure decline method, the per pound drop from the original pressure down to a pressure of 333.66 pounds should represent the same volume per pound drop as the volume per pound drop over the period 1937 to 1938, and that would be true for the periods 1936 to 1937 and 1935 to 1936.

I have stated that I prepared Exhibit 35 and that the different colored bands, yellow, green, red, blue, and gray, represent my views of the relative productivity of the areas

of that field. I have also stated that in my judgment the wells in those areas colored yellow would make from 40 million cubic feet per day up, or would have, had they been drilled at virgin pressure; that wells in the green bands would have made, if drilled at virgin pressure, from 25 to 40 million cubic feet per day; that wells in the red area would have made from 10 to 25 million cubic feet per day; that wells in the blue area would have made between 5 and 10 million cubic feet per day; and that those in the gray area would have made below 5 million, down to zero. I mean by that last statement that all the acreage colored in gray is not, in my judgment, productive of natural gas. I have included it in Exhibit 35 because it is within the outline of the field the Railroad Commission used in 1937. I have simply adopted the Railroad Commission's outline of the field and then have backed my judgment as to whether some of that area is productive of gas.

My attention is called to the fact that on Exhibit 17 Mr. Peterson showed an area which he portrayed as being barren, due to what he believed to be a fault. That barren spot is not shown on my Exhibit 35 because I treated that area just as I have treated numerous other parts of the gray in which dry holes have been found. In reality, that dip of the gray color into the field in southwest Moore County drops down and includes the dry hole that has been mentioned, the Texoma Brown No. 1, and it is so indicated on my map. I did not put it there because it does not appear on the Railroad Commission's map. The outline of the field I am using is that which the Railroad Commission used, and in using that outline, even though there are dry holes within that outline, I did not revise it. I did not cull out what I considered the dry spots in the field in actual area. However, in computing my reserves I did not back my judgment as to whether all of the area included by the Railroad Commission in the field would produce gas.

In my judgment, these areas of productivity, that is, of potentials based on original pressure in the field, as portrayed on Exhibit 35 in the bands of yellow, green, red, blue and gray, represent the relative quantities of reserves
225 originally in place in those respective areas.

In computing my estimate of reserves I have given weight to the relative potentials of the wells on the theory that there is a direct relation between the potentials of the wells and the per acre content in the immediate vicinity of the wells and in the band in which the well is situated. I

applied to those potentials a factor of .919211. That factor, after having been applied to the average potentials in each zone, gives the amount of gas at zero bottom hole pressure within each zone. As stated, the area colored yellow, corrected back to virgin pressure of 430 pounds, had potential open flow capacities ranging from 40 million to over 100 million cubic feet per day. I applied that same factor to that yellow area and obtained an average potential of 60.3959 million. I considered that the wells in the yellow area would have averaged that potential had they been drilled at virgin conditions. That, in my judgment, is the average producing capacity of all the wells that could have or might have been drilled in that yellow area had they been drilled at virgin pressure.

When I got to the green area I applied the same factor to 30.9067 million, which was my judgment of the average potential open flow that would have been encountered in wells drilled in that area at virgin conditions. The same method was used in arriving at the potentials in the green as in the yellow. In my judgment that is what the wells which might have been drilled in the green area would have made had they been drilled at virgin pressure.

After I arrived at the potentials about which I have testified, I applied the factor of .919211 to the area represented in green and also to the areas shown in blue and red. That does not necessarily mean that every well in the yellow area would have made at least 40 million cubic feet.

The comparative figures in the other areas, which compare with 60.3959 million in the yellow, are 16.2301 million in the red area, 6.3697 million in the blue area, and .4651 million in the gray area.

The figure I have indicated for each zone would be the average of the wells drilled in that zone. For example, in the yellow area the figure was 40 million and up, but the average in that area was 60.3959 million. I would not say that every well in that yellow area would have made as much as 40 million. There might be some that would make a little less than that; but they would average around the 60 million.

In order to explain how I arrived at the factor of .919211 which I applied to the average potentials of the various zones, it is necessary to go back to the basic observations which led me to that factor.

The first thing that started me toward the use of that factor was a number of years ago in my experience in that

field watching gas wells drilled in, and having what I considered from first hand knowledge, accurate information that was available to me on that. I mean the thickness of the pays that were encountered and the porosities of the pays. I made the usual calculation based on the porosity-thickness estimation of reserves on that one well, and then after having made the calculation on a well I found that the figure which would result in the expression in mil-
226 lions per acre reserve was almost identical with the figure of the resultant open flow of the wells expressed in millions of cubic feet per day. In other words, the calculation that resulted in an indicated 10 million per acre reserve was also accompanied by a well whose open flow was ten million cubic feet per day, and likewise the calculation resulting in a five million cubic feet per acre reserve accompanied the resultant open flow in a well of five million cubic feet per day open flow. The per acre reserve would simply be the function of the pressure times the thickness times porosity. The basic calculation of thickness and porosity to get the indicated per acre content is the usual formula which is to be found in any text book or handbook defining that method. It was explained here the other day by Mr. Thompson, and it is the method used by Mr. Brown. We call it the porosity-thickness method.

I made that observation on a number of wells which I was watching at the time and on which I considered I had the most accurate information from my personal contact. The amount of variation was an approximate figure, but it was remarkably identical. It was close enough that at that time I decided to use, and did use, in my regular course of professional work a figure which resulted in the application of the factor 1. In other words, from that point on, knowing the relationship, if I wanted to estimate the reserves under a well having 10 million open flow, I would multiply it by one, or use the ten million per acre directly on the ten million open flow.

I did not make a graph of my results showing the number of wells that lay off this line of .919211. In fact, at that early stage of the development it was a process of growth, and the answer was arrived at through observations. The first time I used this method I did not explain it in a report to anybody. As I remember it, the first time I definitely used it was in an appraisal of some gas acreage for the city of Omaha in 1930. That gives you an idea of how far back the general idea had come to my observation. The relation-

ship at that stage, of course, was founded exactly upon the porosity-thickness method. Then later it occurred to me that I would be able to apply that observation to the field as a whole, bearing in mind that it was possible to zone the field. In fact, a little later on, in Mr. Cotner's report it is seen that they zoned the field. If I remember correctly, he zoned the field according to estimates of areas which would produce ten million per day and up and the marginal areas of below ten million per day.

But I went ahead, and instead of stopping at two zones, I arrived at four zones. I had a zone of below ten million, another zone of 10 to 25 million, another of 25 to 40, and a fourth, or highest, 40 million and up. By arriving at an average for each zone I applied the factor 1, or multiplied directly by the open flow the number of acres in the zone, and adding them all together and getting what I considered a reasonable estimate of the reserves in the field. At the time that was done, it was a figure which was remarkably in line with figures which others were using.

Then at that stage of the development I noticed that I had a method that I could check for its accuracy by applying the pressure decline method; but instead of applying it to the field as a whole I would apply it to each zone.

227 Also by that time the procedure of having a field-wide survey made within a reasonable length of time by the Railroad Commission had developed. Prior to that time we did not have a complete uniform survey of the field for pressure conditions.

Having those zones, or rather, the field zoned into four different zones, and having my estimated amount of gas under each zone, I contoured the field and arrived at a weighted average pressure existing in each zone. This was weighted by pressure and acreage of each individual zone. In other words, I found that at that stage I had so many acres of yellow with a resultant weighted average pressure of a certain figure. That resultant figure, being lower than the original virgin pressure, gave me a direct relationship which would indicate the amount of gas or the fraction of the amount of original gas still remaining in place. Or the number of pounds lost from the original pressure to that weighted pressure gave me the fraction representing the amount of gas that each yellow area had lost.

I made a similar calculation then for the next zone, which in this case was the green zone. I took the weighted average pressure in the green zone and by taking the pressure loss

I made the calculation which indicated the amount or fraction that it had lost. Applying that fraction to what I had already estimated was in the green area, it gave me a certain figure. I had already arrived at that figure on the yellow, as I have previously described.

Then I took the next zone, which was the red area. I took the weighted average pressure of the red zone, which again gave me by subtraction the fraction which represented the amount that it had lost, or the amount of gas which had gone out from under it, when applied to my estimate of the original amount there, and I put that figure down.

So far, I have got three figures representing my idea of the amounts of gas that have gone out.

Then I took the last zone, which at that time was the zone between zero and ten millions. I used the weighted average pressure in that zone, and by a similar method I computed the fraction which represented the amount of gas that had gone out of that zone.

Then to test whether my method was correct or not, I added all of those fractional portions of each zone, which were expressed in millions of cubic feet of gas. Then I turned to my production records of the field and found that the production of the field at that time had been a certain figure. The figure was not the exact figure that I had arrived at by my method of calculating what it should have been, and since it was not the exact figure, I calculated to see what factor would have represented the correct figure. That gave me a factor that, as I remember it, was a little larger than my 1 which I described a little while ago and which had been arrived at through the porosity-thickness method; so I decided that since there were some unknown factors in both methods, I would split the difference,
228 and arrived at a factor which at that time I began using by applying it to the open flow, which gave me what I considered a compromise between the two methods. As I remember it, that figure was 1.075 instead of 1.

It was several years ago that I arrived at this factor of 1.075; but by doing what I have described I finally figured it out and obtained the factor I am now using, .919211, and which in my opinion and my judgment is the correct figure to use in order to get an estimate of reserves.

As to how I checked my former work when I revised my figure of 1.075 down to .919211, I will say that in the meantime the zone map which I made when I first started using this idea naturally was based on the wells that had been

drilled in the field at that time. Wells are constantly being drilled in the field. There have been several hundred wells drilled in the field since the time I made the first zone map; so my procedure was to spot the new wells that were drilled in the field to get the information on their open flow, that is, the open flow encountered when the wells were drilled into the formation and before any acidization or shooting took place. In other words, my idea is based on the relationship under natural flow conditions. Since the time I first started it, with the declining pressures in the field, it has also become necessary to be a little more specific in correcting the wells back up to what they would have been at virgin conditions.

So, after spotting the new wells which are drilled in the field on the map, to get their open flows under natural conditions, if those open flows exist at declined pressures, which is the case in a great many from now on, those open flows are carried back in accordance with the Bureau of Mines back pressure method to what they would have been at virgin conditions, and they are spotted on the map. In a great many cases they fall within the zones in accordance with what I have indicated they should be in. In other cases they do not fall within the proper zones, so from time to time I have to revise the delineation of those zones; but as time goes on it has been observed that those changes are of a compensating nature and that within a certain pressure zone of the entire area there will be areas of red, for instance, which must be extended, and, on the contrary, there are areas of red which must be contracted so that they tend to compensate.

Exhibit 35 represents my most recent map, and it represents the picture at about January 1, 1939. I have pointed out that I had an incorrect figure on the Bivins A-9 well in southeastern Hartley County. To be absolutely correct, that well now should show a little circle of blue, or a little extension of the blue in the immediate vicinity, to compensate for that error. There has also been a dry hole drilled in the last month or so in the Hagy-Harrington No. 1 in eastern Carson County, in Section 46, Block 7. Those two areas are in the relatively high pressure area, and would compensate for each other.

In addition to the constant revision of the zone map, we have had to correct pressure losses which I originally started out with. We have had additional withdrawals, so

that those two facts tend toward giving us more cor-
229 rect information as time goes on.

When I make another of these maps I will correct it for the development down in Section 46 and over along southeastern Hartley County, and will make changes in my map from time to time so that the changing conditions will be revealed except that in the case of the dry hole, which I stated was within the Railroad Commission's outline of the field, I will not change the outline of the field at that point. However, the fact that there is a dry hole in the gray area will be taken into account in figuring reserves for that area. I would apply a smaller average figure to the same number of acres. The observation might be made that if the Railroad Commission or anybody would want me to include in that map any additional area which I considered dry area, it would not make any difference in the result which I obtained when I started out in that line.

When I adopted the Railroad Commission's outline of the extent of the field, my outline of the field included 1,200,000 acres, so that by subtraction it would be observed that I considered over 200,000 acres in that gray area to be absolutely worthless. I think I used the 1,200,000 acres at the time I was in Chicago in 1934 for the Peoples Gas Light & Coke Company. I have not changed my mind about its being worthless. I still consider it worthless.

The formula of .919211, I arrived at through a process of experimentation extending over a period of more than nine years. During that time I have spent much time checking the formula and revising it to conform to what I think the changing conditions require in dealing with the reserves. Constantly during the development of that formula I have spent time trying to find a better method, if it was possible to find one, and I have been unable to find a better method.

In the various checks and tests which I have made and which resulted in my adopting that factor, I have used my knowledge of the geological conditions dating from my first contact with the Panhandle in 1922. My first definite intensive study of that field started in February, 1926. Since that time I have devoted most of my time to the Panhandle field and its problem.

It is not my position that the .919211 factor applied to the natural potential open flow at the virgin pressure of a well is indicative of the per acre content in the vicinity of the well in every field in the country. I doubt if there would

be another field where that identical factor or a similar one could be used. There might be some areas in which a similar factor might be used; but it would be a coincidence entirely, and it would have to be arrived at through a procedure similar to what I have used. The factor which I apply is one established by me to my satisfaction by research and experimentation and by a process of trial and error over the years going back as far as 1930.

As I remember it, I broke up the band, which I described as one producing 10 million or less, at the time I de-
230 cided to use the Railroad Commission's outline of the field. I broke what at that time I was using from zero to 10 million open flow band into two bands as shown on Exhibit 35, as representing from zero to five million open flow, and from five million to ten million open flow.

In my judgment the area colored in gray is not productive throughout, but contains a lot of worthless acreage. By that I mean actual dry holes and wells that were drilled which had only showings of gas, and in some cases wells that were reported around one or two million cubic feet open flow. In most cases those wells were drilled in search of oil, and after having found no oil, and either no gas or not enough gas to save, they were plugged and abandoned.

Passing to Exhibit 35, I will describe some of those dry holes so that they can be found on the exhibit. I will now point to a dry hole as shown on this map, and it is a dry hole in fact, at a point four miles west of Benonine in southeast Wheeler County. There is another dry hole a mile southwest of it. There are several oil wells in that immediate vicinity which had no gas. There is another dry hole three-quarters of a mile west of the first one I mentioned. Coming to the two wells in northern Collingsworth County, which is south of Wheeler, shown on this map as two million and 1.8 million, I happen to know that those wells were drilled in search of oil, and not finding the oil, they were plugged back and saved, and I happen to know that those two wells have produced very, very small quantities of gas, resulting in a decided pressure decline, as shown on Exhibit 17, which shows a very low content of gas per acre, because, with small amounts being taken out, it is taking the pressure down very rapidly.

There is a dry hole, although it was shown and listed as a gas well, right at the edge of the town of Shamrock. It is shown on this map as a 1½ million gas well. That well is owned by some clients of mine who have the gas company

at Shamrock, and the well itself is not over a few blocks from the gas office in Shamrock; but yet they go up north several miles to a couple of wells they have there for their gas for the town of Shamrock. In reality that well is not capable of producing any gas in commercial quantities.

These same clients own another well out east of Shamrock, shown as a one million well, and that well is so small that they have not seen fit to lay a pipeline to it, and no one else has seen fit to do so. I might add that those two wells are the wells which are the control points for this yellow area on the pressure map. The control points for the yellow area at Shamrock as shown on Exhibit 17 are the pressure readings on those two wells. One of them, right at the town of Shamrock, is 421 pounds, and the one three miles east of that town is 442 pounds. The one at the town has a potential of 1½ million and the one east of the town has a potential of one million. They are so small that the owners have not seen fit to connect them.

Going on northwest of the town of Shamrock is another dry hole, about a mile and a half. West of the town of Shamrock about six miles is another dry hole. South 231 of it is another dry hole. I might mention that there are some more dry holes outside of this boundary that help the Railroad Commission in showing their line as they do at that point.

Coming on over into Gray County there are a number of dry holes scattered through the entire east half of Gray County. This well in Section 4 was drilled by Upham Gas Company in search of gas, but it was not found, and the well was plugged and abandoned. It was not even carried on down in search of oil. Northeast of that well about two and a half miles is another dry hole in Section 23, Block 25, still in eastern Gray County. They are really so numerous in here that it would take a lot of time to indicate them. There is one in Section 57, Block 25. Here is one in Section 32, Block 25; Section 12, Block 25; here is one shown as a half million in Section 9; a dry hole in Section 20, Block 30, still in the same portion of the county; a dry hole in Section 18, Block H; a number of dry holes in Sections 52, 51 and 70, Block 25; a dry hole at the south part of the field in an irregularly shaped section, Section 1. It does not show the survey, but it is just northwest of the town of Alanreed, about three miles. There are a few wells through here that record two, three or four million.

In that connection I happen to know that it was quite

common in the drilling of an oil well, if an operator encountered just a small amount of gas, he would show on his log a couple of million of gas. In other words, many of those wells were never even gauged, for practical purposes. I know that in some cases there was not even that much gas, but it is easy in making up the log to say, "Well, it had a couple of million of gas."

Those wells which show one or two million are located south of the barren island. There is a dry one in Section 111, Block B-2. Now we are over southwest of the barren island. There are a few oil wells. There was a development in that area southwest of the island in search of oil which resulted in the finding of some small quantities of gas, and the drilling of some wells there, but they did not find any gas. That would still be in Gray County. The last area I mentioned would be Sections 79, 101, 102, 110, 81 and 111, Block B-2. There is a dry hole in Section 187, Block B-2.

We come around now to the most recent dry hole within the boundary of the field, which I mentioned before, the Hagy, Harrington & Marsh No. 1 Dillard, in Section 46, Block 7, Carson County. In Section 14, Block 7, is a one million foot well. Coming on around the edge of the field, where the wells are small, I do not see any completely dry holes within the area that the Railroad Commission shows here until we get around to the well that was mentioned earlier this morning as the Texoma Brown No. 1, in Section 6, Block 2, G & M, in southwestern Moore County.

There is a little fault where that dry hole came in. Mr. Peterson maps a fault there. That is the fault he was talking about.

There are still more small wells in the area, going
232 on around northeast in Moore County, of figures of two million cubic feet, two million cubic feet, and three million cubic feet, until we get into another area in which more wells have been drilled in search of oil, and that also resulted in a number of dry holes. That area is west and northwest of the town of Stinnett, in western Hutchinson county. It is not in the area uncolored on the Railroad Commission map of 1937 and I believe that in that vicinity they have not changed. The part I am referring to is along the line just west of the town of Stinnett, and apparently that is the same line that I have on my map—the line going out to the edge of their colored area.

I might explain that on my map I stayed with their outline of the gas portion of the field, and I did not put in the additional line which starts at about the town of Pampa in northwest Gray County and more or less parallels the line of the gas field, again coinciding with it at a point in northwest Hutchinson County.

The oil wells shown on Exhibit 12 in the uncolored portion are outside my line. They are outside the Commission's free gas portion of the reservoir.

Some of those dry holes northwest of Stinnett are to be seen in Section 7, Block M-24, Section 30, just south of Block M-24, in the G-Bacon Survey, in the W. M. Cole Survey. Although it is shown as an abandoned well, it reported a million cubic feet of gas. Coming on southeast, we are in the oil field area, and there are a number of those wells which do not account for appreciable amounts of gas. When I say oil area, as I have just used that term, I mean the oil area within the colored or free gas area represented on the Railroad Commission's map. Although theoretically they are in the area of free gas, there are places through there where no appreciable quantities of gas were encountered.

I have used the Railroad Commission's delineation of the free gas bearing portion of the field as of 1937 instead of 1938 because I saw no definite reason why I should make the changes that they did in general, and I saw one change which, when it was called to their attention, they admitted should not have been made. That has been mentioned before. It is the area in central Carson County in which there was an error, probably in draftsmanship, in locating some wells in the south and southwest portion of Block 5, I. & G. N. Survey, which in reality were located in similar sections numbered in Block 5, B. & B., or Block 3, A. B. & M. It seems to me that when I checked up there were two blocks involved in addition to Block 5. The correction has not been made on the map which has been offered in evidence. The erasure which can be seen on that map is where they made their change, but the map has not been corrected. The blurred part on Exhibit 12, the 1938 map, is the correct delineation of that line.

Exhibit 35 shows by symbol what the dry wells are. I have not estimated the per cent of dry holes to the gas wells in the gray area. My figure of .4651 as the average content of the gray area takes into account all the dry holes and the areas which in my judgment they condemned.

The symbols used on Exhibit 35 for gas wells are
233 circles with six little diameter projections, or prongs sticking out in what might be called a star arrangement. The dry holes have only four. It would be the effect of a cross over a circle, and the oil wells are just black circles. The point to which counsel refers in Section 12, Block 25, H. & G. N., Gray County, is a dry hole, just a little circle with a cross through it, whereas a circle with several prongs making it look like a star or an asterisk signifies a producing well.

A number beside a gas well represents the open flow in millions of cubic feet daily. If there is a number beside an oil well, it refers to the amount of gas it encountered while it was drilling. However, the fact that there is not a figure beside an oil well does not mean that it did not encounter gas. We could not readily put in all the control points in the oil area.

Exhibit 18 is now presented to me. I am familiar with that drawing. It is a copy of a cross section in the Cotner report, and portrays the fault which exists in Potter County near the southwestern edge of the gas field about which we have been talking. It is along the straight line running in a southeasterly-northwesterly direction along the northern part of Potter County.

On Exhibit 12 are shown some circles below that straight line which I have referred to as a fault line. Those circles are the sub-surface contours of the top of the lime in that area, and they delineate the Helium or Bush dome in Potter County. The dome is called the Bush dome because a number of wells are on land owned by the Bush estate. The first well drilled there was on the Bush estate. That fact gave it the name, and it was afterwards found that it contained helium. It was then condemned by the Government and is the source of most of the Government's helium supply in this country. That dome is faulted off from the main structure of the Panhandle gas field, and this exhibit is a portrayal of the fault line in Potter County.

My attention is directed to the fact that on Exhibit 18 we have expressions such as "Dolomite," "Dolomite Series," "Gray Lime Series," "Gas," and down farther "Oil," and the words "Sea Level" are written below one line. Counsel has inquired what the colored areas on this drawing represent. On that drawing, going from the lowest formations upward, the orange color represents the granite wash formation, the sandy material which was de-

rived from the granite peak. The next one in order is the blue, which represents the gray lime series. The next one is the dolomite series in either a lighter shade of blue or a gray. The next one, in purple, is the anhydrite series, and the top of that is what we call the top of the big lime, although it is not shown. These three series, the anhydrite, the dolomite and the gray lime are all successively below the line marking the top of the big lime.

I am familiar with Exhibit 16. On Exhibit 16 the portion comparing with the anhydrite series on Exhibit 18 would be the formation immediately below the dark line indicated on Exhibit 16 as the top of the big lime. That portion would extend down approximately a third or more of the distance, approximately to where the colored rib-
234 bons occur on Exhibit 16. That point on Exhibit 18 is shown as the dolomite series and it is the dolomite series that contains a portion of these colored ribbons. The dolomite series extends on downward to approximately two-thirds the distance into the big lime series, and beneath it on Exhibit 18 is the portion colored blue, which is the gray lime series, and that gray lime series also contains some of the ribbons which on Exhibit 16 would be largely the ribbons colored in green, in a little triangular portion just to the right of the granite and granite wash.

Counsel has called attention to the red bands changing in color to green bands, going down the structure to water level, as shown on Exhibit 16, and has inquired whether those bands are consistently porous and capable of containing or yielding gas and oil according to the level at which they are found. They occur only in thin bands or ribbons. They do not occur as the complete thickness of porosity, including the formation, is indicated on Exhibit 18.

Counsel has called attention to the fact that as you leave the granite some of the series continue at substantially the same thickness and others seem to fan out into wider thicknesses as you get away from the granite cone, and has inquired whether that means that the producing part of the formation containing oil or gas thickens as you get out there or whether it is the whole series that thickens. It is the whole series that thickens as you go basinward to the right on Exhibit 16—as you go down the structure.

The porous bands or streaks containing the gas above a certain level and oil below that level down to where water begins at another level do not thicken as you go basin-

ward. The portion of the bands carrying gas definitely becomes thinner and thinner, due to the geometry involved in the dipping planes. Many of these bands dip into water long before you reach the east side of the field because they are closer to the mountain and have a steeper decline. Many of the bands which bear oil dip off and disappear into the water at a distance comparatively close to the mountain, taking the whole spread into account. That is typical of the whole situation around the field, except in a few places where the porous streaks even pinch out and become non-porous before they reach that point.

(EXHIBIT NO. 35 for identification, offered and received in evidence without objection.

EXHIBIT NO. 18 for identification, offered and received in evidence without objection.

Document entitled "Volume 17, No. 8, Bulletin of the American Association of Petroleum Geologists, August, 1933", marked Exhibit No. 40 for identification.)

My attention is called to Exhibit 12 and to two areas, one immediately to the northwest and the other to the northeast of the area which has been called the barren island near the middle of Gray County, which are uncolored, indicating that they are oil producing areas which were not originally underlaid with gas, as viewed by the Railroad Commission. I am asked whether that has been the appearance of the Railroad Commission's maps prior to the 1938 map. I am certain that that is not the case. In other words, these areas were colored prior to that time. My attention is called to Exhibit No. 17 which contains what the Railroad Commission calls a pressure contour map of the Panhandle, July, 1938; that has been the appearance of that area on the maps I have seen prior to the map. I don't know how it happens that Exhibit No. 12 has the appearance that it now has. I colored the same areas on my map on the theory that I was following the lead of the Railroad Commission at the time I made it.

235 I have made an estimate of the original reserves of the Panhandle field based on the method of computation which I have described in my testimony.

(Document entitled "Natural Gas Reserves, Texas Panhandle", marked Exhibit No. 41 for identification.)

In computing the reserves I applied a recovery factor. I computed them as of different assumed wellhead abandonment pressures and computed the reserves as of those pressures, using a recovery factor of 90%. From the basic

figure, which represented the gas in place at zero absolute or bottom hole pressure, I calculated the amount of gas which would have been present down to those various assumed abandonment pressures, and then took 90% of that in each different case. I corrected the quantities which I found to be in the reservoir at zero pounds absolute to wellhead pressure before applying the 90% recovery factor. The figures which are shown on Exhibit 41 represent my estimates or computations of the reserves as of the several assumed wellhead abandonment pressures after applying my recovery factor of 90%. Those figures also carry a correction from zero pounds absolute in the reservoir to wellhead so that they represent the recoverable reserves based on assumed abandonment pressures at the wellhead.

I had a reason for applying the recovery factor in computing the reserves of gas down to any assumed abandonment pressure. I had several reasons. One is the fact that at any assumed abandonment pressure, there will still be some gas left in the reservoir higher than that pressure. I know because at the time you cease producing the well you would not have been able to produce from it immediately prior to that time if that were not the case.

Assuming that the red line running from north to south which appears on Exhibit 35, and has been established as the line dividing the East Panhandle field from the West Panhandle field, represents a gas well which is producing from the bottom casing down near the place where the red line runs into the black one. If that well is producing at 25, 50, 75 or 100 pounds, there will be a pressure gradient extending from the bottom of the well out away from the well over the territory that the well is producing from, which will have a higher pressure than the bottom of the well. If this were not the case, the well would have ceased producing, because in order to produce there must be a pressure differential. If you are producing gas to any given wellhead pressure it is necessary in the very nature of things to leave gas in the reservoir which will not be reached at that pressure. The less distance between the wells, the less area would be affected by the outlying higher pressures.

The result down in the gray area, where comparatively few wells have been drilled, will be that those areas will tend to give up a smaller percentage of their gas than the others, if that condition continues through the history of the field. Another factor, which would enter into the per-

centage of the total volume of gas contained in the reservoir which will be ultimately recoverable down to any assumed abandonment pressure, is the effect of water,
236 the source of which in the Panhandle field is both from below and from above. That has an effect in that wells will have to be abandoned and are being abandoned due to the water coming into the wells, both from below and from above, damaging conditions in the well itself, and also from the water getting into the formation.

In the case of bottom water, it can get into a gas well through a condition in which that well itself has been drilled into water, as is the case with many gas wells which were drilled down in search of oil. They did not find oil and drilled into water, not knowing in the early history of the field just where the water was situated. Later on, in plugging that well back to become a gas well, there was an inefficiency of the plugging method. There are numerous cases where the water was not successfully plugged back and came out into the hole.

In the Borger field a great many wells have encountered water. That is an area which forms a direct connection with the underlying water. In some cases it has undoubtedly damaged the producing capacity of the oil wells to produce oil. In other cases as the oil was taken out the water became present in the oil formation. The result of water intrusion on the capacity of the wells in the Borger area within the colored areas has been that it limited them in their capacity to produce gas. In fact, a number of wells have been abandoned due to that cause.

The appearance of bottom water in gas wells has not been limited to the oil areas. There are a few wells scattered through the gas portion of the field itself in which that water has come up from below. I don't know exactly how many. I have made a study or tabulation of the wells which have been drowned out and abandoned by reason of water either from below or above.

(Document entitled "List of Dead and Plugged Gas Wells", marked Exhibit No. 42 for identification.)

Exhibit 42 was prepared by me. I obtained the data from which to prepare it at the Railroad Commission's office in Pampa, Texas, on May 2, 1939.

That exhibit shows a list of gas wells that have been plugged and abandoned and the pressures of the wells at the last test date before they were plugged and abandoned. It shows the tract of land on which the well is

situated, the description, the company name, the number of the well, the lease name, the section and block, the cumulative production in MCF at January 1, 1939, and the date of the last gauge before being shown dead or plugged. That gauge included the pressure pounds and the potential in thousands of cubic feet. In the case of wells that are dead but not yet plugged and abandoned, it shows the first date which is noted on the Railroad Commission's sheet at which the well was shown dead.

89 wells are shown on that list. 55 of them are dead and 34 of them are dead and have actually been plugged and abandoned. The principal difference between the dead wells and the plugged wells is that the dead ones have not yet been plugged. The plugging is accomplished by pulling what pipe is possible to be obtained out of the hole, plugging the hole, and then abandoning it. If you did not plug the well, it would have an effect on the field because gas would still continue to escape. The plug-
237 ging consists of an attempt to plug the hole so as to shut off the gas entirely. It fills the hole, in other words. It might stop the intrusion of water into the formation if it were possible to plug it in such a way as that it absolutely shuts off all the formations; but the chances are that it would not accomplish that purpose.

The Railroad Commission has a regulation requiring that wells be plugged before being left as abandoned. The only distinction between the dead wells and a plugged one is that some dead ones have been plugged and some have not been reached yet.

These wells which have gone out are situated in Carson, Gray, Hutchinson and Wheeler Counties—all the counties except Moore and Potter.

The dates on which the 89 wells went dead are indicated. The date of the last run of gas is indicated in the last column on each page. This list shows that about 40 of the wells were plugged during the last year—40 out of the 89 I think. A great many of those wells went dead in 1937 and 1938. They were still producing at the dates mentioned in the last column. In other words, those are the dates of the last production. Some of them had produced on into 1939 and have gone out in the present year.

I think there is an explanation as to why those wells would be going dead at a more rapid rate in the last year or so than prior to that time. The decline in pressures in the areas results in lower open flows of gas wells, and

less chance for the well to be kept clean of water. With the reduction in the amount of gas that it is possible for the well to make, it lessens the ability to keep the water blown off at intervals. As time has gone on, pressures are reduced. Another factor is the corrosion of the casing or pipe in the well, and the deterioration of the casing seats in the case of cement. In connection with this particular factor the trend is to gain momentum as time goes on. In my opinion, as a result of the tendency to admit more water into the formations, or water into formations of more wells, due to corrosion, and the result of the lack of resistance offered by the gas under pressure in the formation, and the encroachment of water, the difficulty along that line will increase from now on as compared with the difficulty from water in the past. I am influenced in that opinion by the actual history of the field.

The exhibit will not show whether the wells went dead because of water through intrusion into the formation or whether it was because of the rising of bottom water. In fact, it is often very difficult to know for sure which is the case—both being salty water makes it difficult.

(EXHIBIT NO. 42 for identification, offered and received in evidence without objection.)

Cross-Examination Interposed by Mr. Slaff.

Practically all of the wells shown on Exhibit 42 went dead because of water. I have made no segregation between those which did go dead for that reason and those which did not; but from my knowledge of the field
238 conditions I would be able to say that practically all of them went dead from that cause. A case which might be an indirect important cause, but the result of water, would be one where the well became salted up, but the original cause, of course, would be water. It is really hard to think of any other cause for wells to go dead except the intrusion of water.

I don't have the dates these wells were drilled on the tabulation. Those dates are available. Looking over the wells, I am sure that most of them were drilled several years ago. That information would not be available in Pampa, Texas, at the Commission's office; but it would be shown on the logs of the wells. I can supply a list of the dates of the drilling of each of the wells shown on

Exhibit 42. After I return to Amarillo, it will not take very long.

"N. P." under "Pressure Pounds" means that there were some cases where in making the field-wide survey for pressures the condition was such that they were unable to make the test at that time, and they put the letters "N. P." down, which indicates that the well was not prepared for testing. That information sometimes appears under the "Pressure Pounds" column and sometimes under the "Potential" column.

A Bradenhead well is one which is a combination oil well and gas well. It produces gas from a separate casing from that in which it produces oil. It is known as an oil well, and the gas which comes off from that well is called Bradenhead gas. It produces gas from outside the casing in which oil is coming out, but inside of another casing.

Cross-Examination Interposed by Mr. Booth.

The term "Date Last Run" means the date at which the last gas was run from the well and reported to the Railroad Commission's office. The term "Last Date Before Shown Plugged" means the last date on the sheet for the given well in the Railroad Commission's files at Pampa. Often the actual date of plugging was not noted on the sheet, and I copied merely what was available at their office.

Questions by the Examiner.

That date was merely to give me an idea of when the well had been plugged. In other words, it had been tested on the last date shown. They have a sheet in their books for each well. There is just a regular record on that sheet. For instance, there is the pressure and the potential at each survey. On the sheet also is the amount of withdrawal for the various months, so that by looking at that sheet in their files you are able to watch from one month to the next what is being produced by the well. Finally, when it drops off of production, you see that because it shows no run was made. Finally a notation will come along that it has been plugged.

My attention is called to the fact that the dates vary
239 from the second and third months to the seventh, eighth and eleventh months. That is because the usual

date I have copied here shows the date of the last survey of the field for pressures and potentials. In other words, in some years those surveys were made in the months of January and February of that year, and in a good many years they were made in June, July and August. The owner has to make a production report to the Railroad Commission every month and that production report is published in that record. When the well goes off production, no production report is made, and therefore there is no notation about production.

Cross-Examination Interposed by Mr. Booth.

The records upon which this exhibit is based do not indicate which of the wells were plugged as a result of water. I made no independent investigation of the wells to determine which of them were plugged because of water conditions or other conditions. I am unable to state at the moment which wells were in fact dead or were plugged because of water conditions. I can state that the plugging of them was done, but as to just exactly when, I couldn't state. That could be ascertained by getting in touch with the owner of the well. That is not reported any place.

(Statement by Company Counsel that EXHIBIT 42 is offered, not to show how many wells were dead on account of water, but that that many wells were dead as a reason for applying a recovery factor.)

Direct Examination Resumed by Mr. Morgan.

I do know as a matter of knowledge that wells were abandoned on account of water. I was personally acquainted with the history of some of those wells. There are six or seven of the Texoma wells there. Six of them are shown in the Commission's files. As a matter of common knowledge, I know that most of the other wells which have gone dead in that field have done so on account of water.

There are some other factors which would enter into the question of whether or not all the gas could be recovered from the field down to any given assumed abandonment pressure besides increased pressures out around the wells, the water complications and other complications resulting in the well going dead while still having substantial pressure. Those other factors include the reason that the

nature of the formations themselves is such that they are not perfect gas containers. I mean by that that they are not a container that will immediately yield its content of gas. There are areas that have tight formations where the gas is not given up readily.

The reason I did not pick out an abandonment pressure of zero pounds or 25, 50, 75 or 100 pounds and then make one calculation instead of making five in estimating the reserves down there, is that I have definitely arrived at the conclusion that it is not a geological matter alone that allows the answer. In other words, the production problems, the engineering features, and finally the economics of the thing, of any particular type of use for the gas, enter into it to the extent that I do not consider that I could give you an answer.

I have prepared estimates to the several assumed abandonment pressures because I have been asked for the
240 facts at those assumed abandonment pressures. I have computed the recoverable reserves of the field as of January 1, 1939. In arriving at those figures I deducted the production from the figures shown in the column where I set out my original reserves, and made the corrections for the different abandonment pressures. My estimates of the original reserves are set out in the first group of figures immediately under the caption of Exhibit 41. My estimates of reserves in the field as of January 1, 1939, are set out in the next group of figures immediately under that first group.

I have computed the original recoverable reserves under the acreage owned by Texoma on January 1, 1939, at the same assumed abandonment pressures. By that I mean that I have taken the acreage owned by Texoma on January 1, 1939, and have computed the original reserves under that land. Those figures are set out in the third tabulation at the bottom of the first page of Exhibit 41.

In arriving at those reserves, I treated the leases of Texoma tract by tract in the light of the zones indicated on Exhibit 35. I located each tract on the colored band and then applied my original amount of reserves per acre in that band to that lease or portion of the lease falling in that band. I did that for each lease and tract and arrived at the total. For instance, having arrived at the gas in place per acre under the yellow area if there was a lease belonging to Texoma in that yellow area, I applied the same per acre content to that particular lease. If it fell-

partly in the yellow, partly in the green and partly in the red, I subdivided the leases in accordance with the facts, and assigned to that part of the lease which fell in the yellow band the same per acre content as I have given for the yellow, and so on for the other bands into which they happened to fall. I then applied the same method used by me on the original reserves of Texoma that I applied in computing the reserves of the whole field.

I have computed the reserves under the same acreage of Texoma in these different areas in the field by using the same assumed abandonment pressures as of January 1, 1939. Those computations are the first tabulation on page 2 of Exhibit 41. In arriving at those figures I made the same application, tract by tract, that was described in connection with the original reserves, but by observing all pressures existent as of January 1, 1939, on the various tracts, and made the calculation by the pressure decline method, which gave me the remaining amounts of gas in each tract.

I applied the pressure decline method in the case of the Texoma acreage because I had what I considered the correct figure to start with of the original content and the original pressure, so I had the factors of pressure, original content and acreage, which I considered in my estimates of Texoma's reserves, tract by tract, through the use of the pressure decline method.

I do not reject the pressure decline method as a means of estimating the reserves of gas. There is a difference in the things I have done in computing Texoma's reserves and in taking my factor of .9 and so on which I applied in computing the original reserves, and that which I
241 heard Mr. Brown say he used in computing the reserves over the field as a whole by the pressure decline method. What I have done that was not done in his method was to zone the field into five different zones and then apply the pressure decline method to each zone, with the known factors that the zones vary from one to another in the original amounts of gas in place, and knowing the ratio of that variation. In other words, in arriving at my formula, or checking my formula by the use of the porosity-thickness method, I used the relative producing capacities of the various zones which I had colored in yellow, red, green, blue and gray. I took into account in my checking, the relative producing capacities of the several areas that entered into my calculation as I had zoned them.

When I came to apply the same method of computation to Texoma and arrive at its reserves as of January 1, 1939, I had the same known factors, tract by tract, under the Texoma leases. Since I had the original content of Texoma's leases, which I had already arrived at, and knew the original content of the leases, the original pressure in each zone, and observed the present pressure, it was feasible to apply the pressure decline method in computing the reserves.

I didn't apply the method used by Mr. Brown in computing the reserves for the field as a whole. I considered it erroneous because the pressures in the Panhandle are not uniform. Since they are not uniform you would have to assume that each and every acre to start with had equal amounts of gas under them, which is not the case. The pressure factor that must be applied in determining the contents of a gas field by the pressure decline method, when applied to acreage only, is the pressure at which the field would come to equilibrium if it were shut in for a period of time. In other words, the ultimate equilibrium pressure at which the withdrawals at the time at issue would ultimately equalize if every well in the field were shut down. If I wanted to estimate the contents of the field by the pressure decline method as of today, I would need the pressure figures at which the field would eventually reach equilibrium if it were shut in today—the pressure that would result from the production down to the present time.

I have computed the volume of gas which has been drawn from Texoma's leases as of January 1, 1939, whether through its own wells or by drainage, and have classified it between gas withdrawn from its wells and measured, and other gas drawn from those wells. The total amount of gas which has gone out from under those leases as of January 1, 1939, was 730,492,821,000 cubic feet, of which Texoma had withdrawn from its wells and measured into its pipeline 284,852,785,000 cubic feet. This left 445,640,036,000 cubic feet of unmeasured gas which has gone out from Texoma's leases. Of the total withdrawals of gas from leases of Texoma, only 39% has been produced and measured.

The production figures showing how much has been taken and measured from Texoma's wells represent, as I understand it, the total taken from those wells by Texoma and its predecessors. Those are the same figures used by

Mr. Brown and the other witnesses I think, except that they are down to January 1, 1939.

242 *Questions by the Examiner.*

In reaching my estimate of the recoverable reserves as of January 1, 1939, shown on page 1 of Exhibit 41, I did not use the pressure decline method. I arrived at that figure by subtracting from the figure in the previous tabulation the amount of gas that the field had produced. As a matter of fact, I used the figure in Mr. Peterson's tables —the same production figures that Mr. Brown used, except that they were brought down to January 1, 1939. This table is in part based on the Cotner and Crum report.

The figure shown on page 2 for "gas produced and marketed from wells now owned by Texoma Natural Gas Company" is a figure that was supplied by Texoma and is the same identical figure that Mr. Thompson and Mr. Peterson used in that connection. My table of original recoverable reserves in the Panhandle field, shown on page 1, is based upon the data contained on Exhibit 35, as heretofore described.

(EXHIBIT 41 for identification, offered and received in evidence without objection.)

Direct Examination Resumed by Mr. Morgan.

When I explained that in estimating the reserves of the Panhandle field I had divided the field into zones, I referred to the zones portrayed on Exhibit 35. I am not talking about the bands which are shown on Exhibit 12. Those are bands of pressures, whereas my zones are content of gas.

My Exhibit 35 also reflects the open flow or potentials of the wells, which I have related to the actual content per acre in those zones by the method I have outlined.

In connection with my partial list of clients, Exhibit 39, I listed Peoples Gas Light & Coke Company, of Chicago. I also listed Public Service Company of Northern Illinois. I think I should explain those listings. In 1932 I came to Chicago for Peoples Gas Light & Coke Company and appeared as a witness for them, and in that same year I appeared for the Public Service Company of Northern Illinois at Springfield. When I came to Chicago again in

1934, having been called here by the same people, by Mr. Griffith, I assumed that it was for the Peoples Gas Light & Coke Company; but I have been informed that in reality the appearance in 1934 was for Chicago District Pipeline Company. The same man, Mr. Griffith, called me in that instance, and I found him in the Peoples Gas Light & Coke Company building. The first time I knew the testimony I gave at that time was in the Chicago District Pipeline Company matter instead of Peoples Gas Light & Coke Company, was when it was mentioned to me last night that one of those appearances was for Chicago District Pipeline Company.

Cross-Examination by Mr. Booth.

It was my impression that when I testified in 1932 it was a rate case here in Chicago. If I remember correctly, it was before the Illinois Commerce Commission. I testified on the subject of the Panhandle field; but I do not recall what all I did testify to, Mr. Daily was the attorney in that case.

243 *Cross-Examination by Mr. Slaff.*

Within the last five years I testified in the Cities Service case at Topeka, Kansas. I think that was in the spring of 1935. It was before the Corporation Commission in Kansas and was in connection with the rates in Kansas City. I testified on behalf of Cities Service Gas Company. I do not have the date of my testimony with me. It would not be a difficult job to check back in my records and find out the date. I will do that and send it along with the other information which I am to send. The subject of my testimony there was the Panhandle gas field, the reserves, and various other matters. I think that case and the ones I have just mentioned in Chicago are the only rate cases in which I have testified.

As to other cases in which I have testified on the question of reserves in the Panhandle field, I remember I testified in some cases in Texas. I do not recall just what they included. One of them was styled Texoma Natural Gas Company *vs.* Terrell, heard in Austin, Texas, on November 4, 1932, in the Federal Court. I apparently testified by affidavit in that case.

The market demand case has also been mentioned. That

was styled Texoma Natural Gas Company *vs.* Terrell, February 3, 1933. I testified by affidavit.

I also testified by oral testimony in the ratable production case which arose under House Bill 266. That case was styled Texoma Natural Gas Company *vs.* Thompson. There was two trials, one in February, 1936, and the other on the merits a couple of months later. That is the case which finally went to the Supreme Court of the United States, reported in 300 U. S.

There have been some other cases in which I have testified which had to do with drainage conditions and things of that nature in connection with gas. I think I could mention two or three of them. One was for the T. M. Deahl Oil & Gas Company. I think that case was against the Railroad Commission at Austin in 1931. That had to do with drainage conditions of gas. It was in a state court in Texas. The Henderson case had to do with carbon black. That was a case in the Federal Court in Houston in the spring of 1936. I testified by affidavit.

I also made some affidavits for the Attorney General's department of the State of Texas that were used by the State in some cases. My testimony dealt with drainage and pressure conditions of gas. As I remember it, it was in the spring of 1936. I do not remember offhand the cases in which those affidavits were used; but I will dig them up.

There was also a case in connection with gas drainage. I do not know whether you would really call it a case. It was before an examiner in Dallas in connection with the income tax of J. T. Sneed, Jr. That was in the spring of this year.

244 My service on behalf of the City of Omaha, which I referred to, was the making of an appraisal report in connection with some gas properties that were proposed as a reserve behind a proposed line to Omaha. Those properties were located in the Panhandle field. I think that was in 1930. I was engaged by some commission of the city, which I think they called the Utility Commission.

I have not published anything. I don't recall having testified before any legislature bodies—I understand you do not mean to include the Railroad Commission of Texas.

(Note: On June 27, 1939, counsel for defendants, in open hearing, stated that he had been informed by Mr. Hughes that his testimony in the Cities Service case was in Topeka, Kansas, on January 23 and 24 and April 12,

1935. Counsel also stated that the affidavits prepared by Mr. Hughes for the use of the Attorney General of Texas were not used because the cases in which he had prepared the affidavits were dismissed.)

Cross-Examination by Mr. Booth.

The method I used in computing the reserves in Exhibit 41 is similar to the method I have used in computing reserves in other cases, to the extent that due to the time element involved in the history that I recited this morning in connection with the development of that method. I was using the method at that stage. That would be the only difference. Since I perfected that method my standard practice is to use it. As to when the method was perfected, I would have to go back and look at my files. I intended to cover that this morning, both as to chronology and method at the same time. It has been only a difference of my factor, which has changed from time to time, as I have explained here, coupled with the difference in the physical conditions as revealed by a subsequent drilling. The method used has been the same.

In determining the recoverable reserves in other studies I do not recall having set out a number of abandonment pressures as I have here. I have used both methods at different times. Basically, it is the intention to give the basic figures from which any assumed abandonment pressure figure might be calculated. I am sure I have computed abandonment pressures in other cases where I estimated reserves upon specific and single wellhead abandonment pressure, and I am sure that in some cases it was 25 pounds. At times I merely calculated the basic figure that was involved, and the client, or whoever wants to, can make his own calculations. Sometimes I put it on a certain abandonment figure. It it merely a matter of arithmetic carrying it from one to another. That is true also of my recovery factor. If I get the basic figure, it is a mere matter of arithmetic. As a matter of fact, I have used abandonment pressures when I have been asked to do it, and the reason I used 25 here is because I was asked to do it.

It might be that, in computing the recoverable reserves of the Panhandle field in the Chicago District Pipeline Company case, I computed those reserves and expressed an opinion as to the amount of reserves based on 25 pounds

wellhead abandonment pressure. I can refer to the records on that matter readily. I have also computed those reserves at 25 pounds abandonment pressure here, and at several other pressures that I was requested to compute them to. It may be true that in the Chicago District Pipeline Company case I was asked to determine the recoverable reserves in the Panhandle field. I would have to check into that.

245 C. J. PETERSON, a witness for defendants, on being recalled testified as follows:

Direct Examination by Mr. Morgan.

(June 1, 1940.)

(Document entitled "Explantion of Reserve Calculations", marked Exhibit No. 43 for identification.

Document entitled "Details of Reserve Estimate, Marginal Gas Acreage, Texas Panhandle Gas Field", marked Exhibit No. 44 for identification.)

Exhibit 43, consisting of four pages, was prepared by me because in connection with preliminary cross-examination by counsel for the Federal Power Commission and for complainant and by the Examiner, I was requested to prepare a statement in explanation of my reserve calculations. My explanation is embodied in Exhibit 43.

Exhibit 44 was also prepared by me. I was requested to prepare a document showing the details of my reserve estimate of the marginal gas acreage set forth in Exhibit 20. That detailed study is embodied in Exhibit 44. The document divides the marginal acreage up into the fourteen sectors which I used in estimating the reserves of gas underlying that area. Those sectors are described on the detailed explanation so that they can be identified on Exhibit 20. I show the number of acres in each sector or subdivision, and in addition I have furnished the average thickness in feet of the gas pays, the porosity in per cent determined for each sector, and the reserves per acre in thousands of cubic feet. I mean, of course, the average porosity and average reserves for each sector. I also show the total reserves for each sector to zero pounds absolute abandonment pressure in the reservoir on a 16.4 pounds base; also the number of wells used in each sector in de-

termining these reserves, the number of dry holes in each area from which reserves were estimated, and a tabulation of remarks which are explanatory of the factors involved in estimating the reserves.

In Exhibit 28 the figures included these figures here for the marginal acreage corrected to the different pressures therein set forth and after applying a 90% recovery factor. All these matters are explained in my Exhibit 43.

In the gray area shown on Exhibit 20 I found 66 dry holes.

I wish to make a statement or explanation in connection with my description of that gray area. I understand somebody got a wrong inference which I did not intend to give, and the Examiner may have gotten the same impression. I wish to clarify the record regarding the yellow and gray areas shown on Exhibit 20 used in making my estimate of reserves for the Panhandle field.

In order to simplify matters, I divided the field into the gray and yellow areas as shown on Exhibit 20. The whole field is complicated, and in describing the two areas on Exhibit 20 I have used two descriptions for each of the areas
—that is, the yellow area I have described as the "Best
246 Commercial Gas Area, Open Flow Above Five Million Cubic Feet Per Well", and on the gray area I have used the legend, "Marginal Gas Area, Open Flow Below Five Million Cubic Feet Per Well." In drawing the boundary line of the gray area shown on Exhibit 20, I adhered as closely as possible to the legend last above quoted; but I do not want it to be understood in this connection that all the wells in either the yellow or the gray area have an open flow as thus stated. In other words, I wish to make it clear that in the gray area there are some wells with an open flow of above five million cubic feet per well, and in the yellow area there are some wells with an open flow below five million cubic feet per well. However, in figuring the reserves for either of these areas, I have in each case taken account of the respective reserve values indicated by the size and productivity of the wells in each area, so that in the gray area where wells occurred with an open flow above five million cubic feet per day I have used the values thus indicated in figuring the reserves of that area, and in the yellow area where wells occurred with an open flow below five million cubic feet per well I have taken these sectors into account in figuring the reserves underlying the yellow area.

I left some wells in the yellow area which made less than five million cubic feet, instead of creating a gray area, because I was trying to treat the Panhandle field in just two separate areas, and the wells used here which were less than five million cubic feet were surrounded by wells considerably above five million cubic feet. In other words, the average in the yellow area is a great deal above five million cubic feet per well, just as the average in the gray area is a great deal below five million cubic feet per well.

As to whether I can point out on this map a well in the yellow which made less than five million cubic feet per day initially, I will say that it is hard to see it on this map on account of the scale; but I will state that two Texoma wells in that area made less than five million cubic feet per day, but surrounding them were wells of considerably higher open flow capacity, so I left them in the yellow area instead of creating a dozen different areas in the field. The wells I refer to are Texoma Coon No. 1-M, located in Section 149, Block 44, H. & T. C. Ry. Co. Survey, in Moore County, and Texoma Coon No. 2-M well, located in Section 151, same block and survey. There are some others too, but I do not just remember the locations now.

When in a few instances I found a well in the gray area which made above five million cubic feet but which was surrounded by wells making less than that, I used those wells and gave them their proper weight in estimating the reserves in the gray area.

(EXHIBITS NOS. 28, 43 and 44 for identification, offered and received in evidence without objection.)

247 STANLEY GILL, a witness for defendants, testified as follows:

Direct Examination by Mr. Morgan.

(June 2, 1939.)

My name is Stanley Gill. I am forty years old, and live in Houston, Texas. My profession is that of an engineer engaged in consulting practice, principally in the field of petroleum engineering. By that I mean engineering problems in connection with the production of oil and gas. I am not employed by any particular concern, but I am in the

general practice. Of course, I am retained by various concerns, and practice throughout the State of Texas.

I graduated from the University of Washington with the degree of Bachelor of Science in Mechanical Engineering, and followed this training with the completion of a three year graduate course in engineering at Columbia University, from which I graduated with the degree of Chemical Engineer in 1923. Beginning in January or February of 1923 and for a year thereafter, I stayed at Columbia University as an assistant in the physics department and later in the chemical engineering department. I also engaged in a rather miscellaneous and wide-spread independent consulting practice in chemical engineering. While at Columbia I was assistant in the physics and chemical engineering departments. I was a member of the faculty at that time, which took about a third of my time, the balance being spent in consulting work.

In February, 1924, I was employed by the Mellon Institute of Industrial Research at Pittsburgh, Pa., and was immediately assigned to work for the Gulf Production Company, which at that time was the producing subsidiary in Texas, Louisiana and Arkansas of the Gulf Oil Corporation. I was sent to Houston, Texas, for the Gulf Production Company in February, 1924, and remained there with them until the end of 1931. During the first four or five years of that period I was employed by the Mellon Institute of Industrial Research, and during the latter part of the period I was directly employed by the Gulf Production Company as a member of their research department.

In the beginning my duties were concerned almost entirely with the investigation of corrosion problems. As time went on my work extended into all phases of production engineering, principally from the research angle; and during the latter part of my employment there I was head of the division of the Pittsburgh research department and was assistant head of the Houston research department, in which we had twenty or thirty production engineers engaged primarily in petroleum production engineering research.

Beginning in January, 1932, I entered the consulting practice in Houston, and have been engaged in that practice since that time.

248 I have said that the professional work I do in connection with my practice has to do with production problems of the oil and gas industries. The work that I

have done, and do, covers a very wide range. It goes from consulting work for manufacturers of oil field equipment, in connection with the design and testing of certain of their equipment, through field work, beginning with certain phases of exploration through drilling. At times I have specialized in drilling mud problems. I have been employed to supervise drilling operations under some rather difficult conditions where wells got into trouble; to testing and general engineering supervision of production operations in certain fields and areas—in fact, all phases of engineering work in the field connected with oil and gas production. I do a very considerable amount of estimation and appraisal work on oil and gas reserves. I have been employed from time to time as an expert in connection with litigation of a great many types.

My practice has not been confined to the State of Texas. I do a great deal of work in Louisiana, and have done scattered jobs in Arkansas and Oklahoma, and one job in California. At the present time I am engaged in some work in connection with the Turner Valley oil field in Alberta, Canada.

My practice has taken me to the Panhandle oil and gas field. I have been keeping in touch with and making a study of the conditions in that field since late in 1926 or early in 1927. I remember that I was in the Panhandle in April, 1927, and that was my second or third trip. My first work there was in connection with corrosion and water problems in the oil area. Since that time I have been intermittently in and out of the Panhandle field in connection with all sorts of problems.

I am familiar with the extent of that field and its general structural conditions, as well as the pressure conditions that obtain throughout the field. I have seen the pressure maps which were offered in evidence in connection with Mr. Peterson's testimony and have carefully examined them. In the light of what I know about the situation, I understand the pressure conditions to be as portrayed on those maps and by Exhibit 12.

I am familiar with the conditions as to productivity throughout the field, especially with reference to whether it is uniform or variable as to gas wells. The field is highly variable, and has very wide variations in productivity. I would say that the range of variability in productivity which obtains in the Panhandle as it is defined

by the record here, as it appears from Exhibit 12 and other exhibits which I have seen offered in evidence in what is considered more or less commercial area is a variation of 50 or 100 to one. Some are 50 or 100 times as large as others. There are also dry holes in that area.

I am familiar with the structural conditions showing where the oil, the gas and the water in that field are located with reference to each other. Of course, I know those areas from conditions on the ground. I have never made any independent structural studies; but I have examined a great many very thorough studies, and consider myself familiar with the conditions. I have not examined the logs of wells in that field systematically; but I
249 have seen a great many of the logs and studied them for special purposes.

In that field, from a geographical standpoint, gas is located generally toward the southwest. The oil is along the northeast flank, and the free gas to the southwest of it. There is free gas in the same geographic location as the oil; but it does not extend over all the area from which oil is produced. It is a usual situation; that is, the gas exists within the same porous formations above the general level of the gas-oil contact.

Structurally, the relationship of the water, oil and gas in that field is the usual relationship—water on the bottom up to a general level of the water-oil contact, and then the oil up to a general level of the oil-gas contact. I don't remember just how far above the water-oil contact the gas-oil contact level is, but there are some couple of hundred feet of formation. Gas is above the level of the gas-oil contact. When I say a couple hundred feet of formation I mean vertically. It does not mean that much porosity, but that much vertical distance. That distance is several miles horizontally along the Panhandle field.

I am familiar with Exhibit 16. I have known it pretty well for three or four years, and have seen it used in one other proceeding, to-wit, the case of *Texoma* v. *Thompson*, which finally became *Thompson* v. *Texoma*, reported in 300 U. S., which has been referred to here repeatedly.

There is no significance to the circumstance that the line which has been referred to here as the level of contact between water and oil is substantially at sea level. That is just where it happens to be. If you run into a porous part of the formation which extends on down be-

low that level of oil-water contact, the porosity is filled with water, and from that level upward is found oil, until you reach the level of the oil-gas contact, and then from that part up you find gas.

I have a very definite opinion as to whether or not there is free gas in the space between the level of the oil-water contact and that of the gas-oil contact. I don't believe there was originally any appreciable quantity of free gas in that part of the porous formation in the Panhandle field lying between the general level of the water-oil contact and the general level of the oil-gas contact. There was a little bit of gas in solution in the oil.

I have done a great deal of work in the field of chemistry and physics to learn something about the capacity of oil to absorb gas, and have read rather extensively on it. By the term "gas in solution" or "gas in absorption" in the oil, I mean that it is gas which is dissolved in the oil. It is gas which exists in the liquid phase. To make a rigorous definition, I think you would probably say that the gas in solution is that portion or that part of the hydrocarbon system which we normally consider as gas, which, under the conditions we are considering, is a part of the liquid phase. It is like the carbonated gas in a
250 bottle of beer. It is just like that gas that is dissolved in the liquid.

There is no distinction between the terms absorption and solution. Absorption is not a very good term. That term comes into this industry from the fact that one method of recovering natural gasoline from gas is referred to entirely as the absorption process. In that process the gas is passed through absorption towers, and the gasoline constituents are dissolved in the oil and taken out of the gas. That is the reason that term absorption is used in this industry. Solution is the correct term. It is really gas in solution or dissolved gas.

I have made no tests of the solubility of Panhandle oil or its capacity to absorb gas; but there is not a wide range in capacity to receive gas in absorption among the different types of oil. Going back to the basic theory of solution of gas under such conditions, it is a matter of the vaporization equilibrium constants of the individual constituents. Those equilibrium constants are commonly referred to as "K" values. I am not going into the theory unless you ask me to; but the results of the application of

that theory, which is supported completely by all tests had, leads to the conclusion that the composition of the liquid oil has very little to do with the solubility of gas, but that the composition of the gas is the controlling factor. The result of that is that gas of a given composition will have roughly the same solubility in different crudes of approximately the same gravity.

There may be a wide variation between natural gases as to their solubility in oil, because there is a wide variation in the composition of natural gases. I have analyzed gases that ran all the way from 40% to 90% of methane, which is one of the principal constituents of natural gas. In the Panhandle gas it is very much a constituent.

With respect to the probable range of solubility as between Panhandle oil and other crude oils, so far as gas composed largely of methane is concerned, I would say that for dry gas in this territory the solubility of Panhandle crude will be just about the same solubility as any other crude of about the same gravity.

By the expression "composition of gas" I mean its chemical analysis—so many percent of this, so many percent of that. The big percent of Panhandle gas is methane. It has also the usual series of light hydrocarbons. Methane is the widest of the naturally occurring hydrocarbons. That is what we call the paraffine series. There is methane, ethane, protane, isobutane, butane, pentane, hexane, heptane, octane, and so on up. For methane the chemical term is CH_4. Ethane is C_2H_6. Protane is C_3H_8, and so on. That series carries a general formula of C_nH_{2n}, and from this are the steps of that series. I think duodectane is the name of the one that is the twentieth. That would be $C_{20}H_{42}$.

In a gas which carries from a quarter to a half gallon of recoverable gasoline per thousand cubic feet, the
251 percentage of methane will normally run anywhere from 80% to 90%, with a small percentage of ethane, usually, and of the higher constituents. There are exceptional cases which carry high concentrations of those higher hydrocarbons. The Panhandle gas is high in methane. It also contains considerable nitrogen, which is a fixed gas and serves just as a diluent as far as the solubility relationships are concerned.

This gas which is in solution in crude oil formations in the Panhandle gets to be gas by passing out of solution

as the pressure is reduced. In other words, when the well is opened, the reaction in the oil as it starts through the well to the surface is like the uncorking of the bottle to which you referred. The gas begins to bubble out of the liquid. It is that pressure which holds it in solution. Whether there is a pressure point at which the freeing manifests itself depends entirely on whether the oil is saturated or not. If it is saturated under any given pressure, some gas will come out of solution as soon as there is any reduction in pressure. If it is not saturated, the pressure can be reduced down to the pressure corresponding to the amount which there is in it.

All of the oil in the Panhandle field is not saturated. I would say that some of it is not saturated at all. The oil in the formation is under-saturated. When it is saturated, it has the maximum amount of gas dissolved that it can hold. When it is saturated, you cannot get any more into solution. In a sense it could be compared to a sponge that has been dipped into water or some liquid and which has taken up all that it will hold. A better comparison is a glass or cup of coffee. You can put one spoonful of sugar into it and fill it up and it will dissolve all of it. All of that sugar will go into the liquid. You can put in another three or four and it will still take it all up; but if you put in eight or ten, no matter how much you stir it, you can't make that coffee take up all the sugar.

I have an opinion about what the saturation point of Panhandle crude would have been under the original reservoir pressure. I think it would be not very far from 100 cubic feet of natural gas per barrel.

Questions by the Examiner.

There is a state that can be compared to an emulsified oil, which would enable the oil to have a comparatively higher gas composition than you would get by simply dissolving gas into the oil. It is a condition under which minute particles of gas are disseminated through a body of oil. That is not an equilibrium condition. It is a condition we get in oil fields after production has started, when pressure through parts of the body of oil has gotten to the point where the pressure of the oil still way back in the formation is reduced so that the gas starts coming out of solution. Under that condition we do encounter

dissemination of those minute bubbles of gas throughout the oil body; but so far as I know, that condition has never been encountered in a virgin oil-bearing formation, and I don't think it ever will, because through geologic time those minute bubbles will be sorted out by gravitational action and separated from the oil, but it is a condition
252 which is definitely encountered in fields that have produced some oil.

That would not give you a higher gas-oil ratio than if you had gas in solution. It will go to the original solution point. In other words, that gas was in solution when those formations were first penetrated, and then as the gas and oil were withdrawn and the pressure reduced back in the formation, some gas would come out of the formation, but it would produce a homogeneous mass of oil with little bubbles of gas which will have the original gas-oil ratio.

There is such a phenomenon as gas bubbling through the oil and giving the oil a higher gas-oil ratio. In that sense it is not emulsification, except theoretically. You get a foamy condition, and you get it in the strings of the well from which oil and gas are flowing under certain conditions. As to that in the formation, it becomes guesswork, but I don't know of its happening in the formation. I don't know of any way that it could; but it does still happen. In fact, it happens all the time that the gas will break through to the opening through backing oil into the well, and you get a downward coning of gas—that is, an inverted cone of gas in the well, holding the oil back. That is because the gas has a viscosity so much lower than the viscosity of the oil that it will, under pressure differential, run ahead of the oil. That is a very common phenomenon.

Direct Examination by Mr. Morgan (Resumed).

The gas-oil ratio is not synonymous with the gas in solution. The gas-oil ratio, in the units which we usually use, is the number of cubic feet of gas which is taken out of the well with each barrel of oil. That is a measure of what happens at the surface. Gas in solution is dissolved gas, which we have just defined. Here is what can happen. You can't produce an oil well with a gas-oil ratio any lower than the quantity of dissolved gas in the forma-

tion. You can't get any lower than that. If there is 100 cubic feet of gas dissolved in each barrel in the formation, 100 to 1, that is the lowest ratio that you can produce, because each barrel of oil that comes into the well brings 100 feet of gas with it. But you can produce at any higher ratio—that is, the gas-oil ratio may be higher than the dissolved gas ratio by any amount.

In a situation such as that obtaining structurally in the Panhandle, the gas-oil ratio might rise to infinity. If you get a dry gas well, it makes no oil at all, and therefore it has an infinite ratio. If it has a little oil, it depends on how much oil has gotten into the well. It might be a hundred thousand million, or any amount.

In the Panhandle some microscopic part of the gas which comes up might come from the gas-oil contact; but for all practical purposes every bit of the gas will come from above the original gas-oil contact.

I have had considerable experience in computing gas reserves. I am familiar with what is commonly referred to as the pressure decline method of computing gas reserves. That is a calculation of the total quantity of
253 gas originally present in a reservoir by use of the relationship between the production which has been had from that gas reservoir, or which is had from it during any particular interval, and the decline in average pressure, or equalized average pressure, within that reservoir. That method of computing gas reserves is based on Boyle's law.

To apply the pressure decline method of computing gas reserves you must have as known factors the quantity of gas produced during any particular period, and the average pressure within the gas bearing formation at both ends of that same period of time. By average pressure I do not mean the geographic pressure. I mean the pressure to which the contents of that gas reservoir would equalize if the wells were shut in a sufficient time to give the field the opportunity for the establishment of equalization.

I have used that method of computing reserves of a gas field a number of times. It is the best method there is when the data is available. I have used it under conditions where the gas bearing formations were substantially of identical thickness and porosity over the entire producing area of the field. If they are of the same thickness and

porosity, that means they would have substantially the same per acre content. I have also used that method where a correction could be made for differences in different parts of the field—that is, in the wedged edge where the formation dips out under water, and it is possible to make a correction for that difference. The other fundamental, of course, is where you have a completely equalized pressure. There are conditions in a gas field where the pressures are equalized. The most recent estimate I have made of gas was in a field where that was true. There the pressures were within ten pounds, and the average bottom hole pressure was approximately 4000 pounds per square inch. That was the Old Ocean field in Brazoria County, Texas.

I think that method of computing reserves can be applied to the Texas Panhandle field by weighting to a per acre content of the field, which is essentially what Mr. Hughes did in arriving at his constant. He weighted his pressures both to area and to per acre content in order to arrive at an average pressure. I think you get a fair approximation that way.

It cannot be applied to the field as a whole, as was done by Mr. Brown, the witness for the Commission. His method was completely wrong. He did not use the right pressure. He used the pressure weighted to area alone, and the thing is grossly incorrect because it takes into account an area containing a lot of acres which consist of high pressure areas, and which naturally contain very much gas, which gives an incorrect average for application for the reserve estimation.

(Document entitled "Diagram Illustrating Effect of Withdrawals on Pressure", marked Exhibit No. 46 for identification.)

Exhibit 46 is a chart which I have caused to be prepared, from which I can illustrate what I have been talking about.

254 That chart is simply a representation of five gas containers of different sizes, which are noted on the drawing, connected into a manifold with valves, and each carrying a pressure gauge. Container A is assumed to have a content of 25,000 cubic feet of pressure base gas under a pressure of 100 pounds absolute per square inch. Container B is assumed to hold 15,000 cubic feet of base pressure gas under the same conditions; container C,

7,000; container D, 2,000; and container E, 1,000. The total content of all the containers, therefore, would be 50,000 cubic feet of base pressure gas. When I say base pressure gas, I mean if you measure it at 16.4 pounds per square inch.

Assuming that it is desired to withdraw 25,000 of that 50,000 cubic feet, we could get it from one container or we could get it from several containers. If you take 25,000 cubic feet out of container A the pressure would be sucked down to absolute zero. If you didn't take any out of the other containers, the pressure in A would be down to zero absolute, and you would have 100 pounds absolute in each of the other containers, and the arithmetical average of the pressures prior to equilibrium would be 80 pounds per square inch. That would be a withdrawal of 1250 cubic feet average per pound drop in your average pressure. If that reduction per pound drop were applied to the original pressure of 100 pounds, you would have 125,000 cubic feet as the original content of the entire system, which would be two and one-half times as much as was actually there.

If we take 15,000 of the 25,000 cubic feet out of container A and the other 10,000 out of container B and none out of the others, we would have taken 3/5 or 60% of the gas which was originally contained in container A, so its pressure would be 40 pounds absolute. We have taken $\frac{2}{3}$ of the gas originally in B, so its pressure would be $33\frac{1}{3}$ pounds per square inch absolute. The arithmetical average pressure of the five containers is 74.7 pounds per square inch absolute, which is a pressure drop of 25.3 pounds per square inch reduction in average pressure, and the production for each one pound of that drop would have averaged about 980 cubic feet. The application of that average to the original pressure would represent an estimated original reserve of 98,000 cubic feet, or approximately twice the actual reserve.

You would get a different result most anyway you distributed your withdrawals. Taking that same chart, you can withdraw the same quantity of gas from different containers and get different average pressures prior to equilibrium and a different indicated original reserve each and every time you do it. Those arithmetical average pressures after withdrawal will range all the way from 50 to 80, depending on how the withdrawal is dis-

tributed. 50 is the equilibrium; but we can go to the other side of 50 in this way: We can take all the gas out of container B, and all the gas out of containers C, D and E, and pull them all down to absolute zero. That would give us a withdrawal of 25,000 cubic feet. We have left the initial pressure in container A. The arithmetical average pressure would be 20. I don't know what the reserves would be; but it would be a very low figure. The result would be on the other side if the production was from the lean end of the system of containers.

255 So long as the greater proportion of the production has come out of the large containers, that method will lead to an over-estimation of reserves; and the other way will lead to an under-estimation.

In the Panhandle field, the large production as a whole has come out of the best part of the field, where the original content was greatest—in other words, to make a wide jump by analogy, from containers A and B. Therefore, if you average the pressures in the different areas as the Railroad Commission did it in arriving at what it called a weighted average pressure, the indicated reserve will be an over-estimation.

If there had been heavy withdrawals from the south and southwest parts of the Panhandle structure and relatively lighter withdrawals from the northeast, an application of pressure weighted on area would lead to under-estimation of reserves. As it is, that application leads to a large overestimation.

I have caused another drawing to be made by which I have sought to apply the principle demonstrated by this system of containers to the conditions existing in the Panhandle. It shows principally that the assumed sizes of those containers are in reasonable accord with the proportion which actually exists in the Panhandle field.

(Document entitled "Variation in Productivity of the Panhandle Field, Cross Section from South to North on the Carson-Gray County Line," marked Exhibit No. 47 for identification.)

That chart is essentially two charts. The upper is a rock pressure profile from south to north along the line between Carson and Gray Counties. The horizontal scale which is indicated both at the top and the bottom of the chart shows the sections which that line cuts across. Most of those divisions are a mile. The upper part of the

chart simply shows the rock pressures across that line of section. It is based on the Railroad Commission's 1938 rock pressure determinations.

The lower part of the chart is a cross section along the same line based on Mr. Hughes' map, Exhibit 35, and shows the variation in productivity across that section.

Comparing it to Exhibit 35, I point out that the cross section is along the line between Carson and Gray Counties. Starting on that line at the south boundary of the field on Exhibit 35, you can see that there is a little bit over three miles colored in gray, which is classified as having an open flow of less than five million cubic feet per day.

On Exhibit 47, the first part, starting from the left and corresponding to the south end of the section, is shown with a productivity of less than five million. It is idealized somewhat by being tapered off to pretty nearly zero at the extreme south boundary, which is probably the actual condition.

256 Returning to Exhibit 35, after leaving the gray zone on Exhibit 35, that county line traverses approximately eight miles of blue, which is zone classified as having open flows between five and ten million cubic feet per day. On Exhibit 47 that eight miles is shown in blue, and the upper line, productivity, runs between five and ten with this hump in Section 236 being put in there because of a well which actually exists very close to the section at that point.

On Exhibit 35, after leaving the blue, the county line traverses maybe a mile and a half of red, then a little bit less than two miles of green, then another mile of red, and then a little bit more green. On Exhibit 47 these zones are colored in the same colors that were used on Exhibit 35 and to scale as to length to show that the county line traverses these zones in the case of red of productivity between ten million and 25 million, and in the case of green of productivity between 25 million and 40 million. The county line toward the northern part of the field traverses something over two miles of yellow zone, which is classified as the area in which open flows are above 40 million feet. This same distance is plotted in on Exhibit 47 as a zone in which productivities range from 40 million upward to 60 million. This again is a

little bit idealized at this point. 60 is actually the average for that zone, according to Mr. Hughes.

Passing north of that area of yellow on Exhibit 35, the county line traverses for short distances zones which are colored in green, red, blue and gray, and then leaves the field. These same belts are plotted into both horizontal and vertical scale on Exhibit 47. In other words, the thing is a productivity profile of the field along that line.

Questions by the Examiner.

If I had followed Mr. Hughes' map I would have used blocks instead of curve to illustrate the proper profile of my productivity curve. A correct or rigorous following of Mr. Hughes' map would call for a block plot. This is rather an idealized thing for illustrative purposes, and it does show that the actual proportions of zones in the field across that line of sections are in reasonable accord with the proportions we have assumed in constructing Exhibit 46. That is its only purpose.

Direct Examination Resumed by Mr. Morgan.

A comparison of the rock pressure profile of Exhibit 47 with the productivity profile shows conclusively where that heaviest withdrawal has been. As shown by that exhibit, we still have pressures up around 425 at the edge of the field. Toward the left of the south cross section we still have pressures which are virgin, or substantially virgin. That area corresponds, as is shown by these two different profiles, with the zone of least productivity. Then passing north the rock pressures become progressively lower down to a minimum of considerably less than 100 pounds, though it is shown here as 100 pounds minimum, at the north edge of the section, with the greater part of the low pressure zone corresponding to the areas which are colored in red, green and yellow on the productivity profile. That shows that the heavy withdrawals have been from the more productive part of the field.

257 If the pressures in the field along the bands portrayed on Exhibit 12 are taken, and the arithmetical average of the pressures of each band is taken, thus arriving at an average pressure into which only pressure

and area have been weighted, a very large error results from applying the pressure decline method of computing original reserves. That error leads to over-estimation of the original reserve.

I took that particular cross section because it was just a handy place, and it was easier to set up one there that had quite a little bit of blue in it than it would have been to come up here to Potter County and Moore County, where we have a larger proportion of blue but where the section would have been much more complicated. We could have shown the same kind of a proportion, but it would have made a more complicated profile, and we just picked that spot because we had a pretty good distance across the field and it had a reasonably simple distribution of the zones. The same thing could have been shown by a section anywhere else. If I had gone into Moore County or up through Carson and Hutchinson Counties, I would have had the same variations in productivity, but they would have been in a more complicated succession.

Exhibit 26, a report of the Railroad Commission dated July, 1938, is now presented to me. There is a tabuation on page 12 of that report which shows the acreage within each of the pressure belts on Exhibit 12. This table on page 12 shows at rock pressures below 150, 59,947 acres, which is 4.1% of the total acreage; at pressures of 150 to 199, 78,159 acres, which is 5.3% of the total acreage; at pressures from 200 to 249, 117,435 acres, which is 8% of the total acreage; at pressures of 250 to 299, 145,579 acres, which is 9.9% of the total acreage; at pressures of 300 to 349, 154,805 acres, which is 10.5% of the total acreage; at pressures of 350 to 399, 524,495 acres, which is 35.5% of the total acreage; and at pressures of 400 plus pounds per square inch, 394,904 acres, which is 26.7% of the total acreage.

The yellow and green zones on Exhibit 12, which take in everything having pressures of 350 pounds per square inch or higher, cover 62.2% of the total acreage. From my knowledge of the field, it is my judgment that there wasn't anything close to 62% of the total original reserves of the field in those two belts.

As to whether I have calculated it in any way, I have made some rather extensive studies attempting to get at precision figures on drainage. As I said earlier, I

have never estimated the reserves of the Panhandle field; but I have made some rather extensive comparisons of pressure drops and withdrawals in connection with drainage studies. Although those have not even led me to a definite proportionality between original reserves in different parts of the field, they do show very conclusively that that large area to the south and southwest is the lean area of the field—that it originally contained much less gas per acre than the fat part of the field.

If we make different distributions of area, and weight by area, we would get different results, and all of the 258 results would be wrong when applied to reserve estimates. If there were low pressures in lean areas, you would get one kind of error, whereas in the low pressures in another content you would get another kind of error.

If the heavy withdrawals have been from the rich areas, as they have in the Panhandle, the application of these average pressures weighted only on surface area will lead to an overestimation of reserves. If the larger part of the total area is in those rich areas and we weight in by area, that will tend to reduce the error. If the larger part of the total area is in the lean portions of the field, which have had the light withdrawals and which are now areas of high pressure, as is the case in the Panhandle, weighting by area will increase the error and give an even greater overestimation than we would have on arithmetical average.

The sum total of what I have said is that in order to apply the pressure decline method in computing reserves of a gas field, you must know the ultimate equilibrium pressure to which the field would settle were it shut down as of the time of the inquiry, and there are conditions under which that can be calculated. There are field conditions under which that equilibrium pressure can be determined; but this pressure factor cannot be determined in the Panhandle by weighting the average of pressures in each area with the extent of the area, as was done by the Railroad Commission in arriving at that factor of 337.66 used by Mr. Brown in his computation.

I am familiar with what the Railroad Commission did in arriving at that 337.66. Referring to Exhibit 12, which is the Railroad Commission's pressure map, and particularly to the gas wells in the gray area along the northeast flank, the Commission, after having determined the rock pres-

sures of the gas wells in that area, added those rock pressures together and divided by the total number of wells for which they had measurements, and thus arrived at the arithmetical average of the rock pressures of the wells on which they took tests expressed in terms of per pound per square inch gauge. Then they went to each band and did the same thing, with the result that they took the average of the pressures of the wells in the yellow, the green, the blue, and on through the field in the different bands, and then multiplied each of those average pressures by the quantity of acres contained in each band, obtaining as many results as they had bands, and then they added those up and divided by the total number of acres.

The pressure factor, which they multiplied the acreage by in the yellow band or yellow zone, was the arithmetical average of the pressures of the wells in that zone, and those pressures varied from 400 to 430. When they got over in the green those pressures varied from 350 up to 399; and they had the same variation of 50 pounds in each one of those bands, as the legend on the map shows.

If we start with the assumption that weighting of pressures by area alone will lead to an average pressure and that that figure is correct for purposes of reserve estimation, then, in other words, it would lead to the adjusted equilibrium average pressure within the reservoir. If we assumed that one method of weighting to area will do it, then other subdivisions of areas should lead to the same
259 correct result. What I mean is that if those particular fifty pound bands would do it, twenty pound bands should do it, dividing the things up into squares should do it, or most any other way of doing it. The one correct number would not just happen to be the one you would hit by splitting up into fifty pound bands and averaging certain wells. In other words, Mr. Boyle, when he developed his law, never heard of the Railroad Commission or that map; and it would be just as logical and just as feasible to arrive at these weighted average pressures in which only pressures and areas are concerned, if we weighted by counties touched by that field instead of these yellow, green, blue and so on bands across there.

I have zoned that field by counties and made exactly the same kind of calculation that the Railroad Commission made in arriving at that 337.66. I have that tabulation in such form that it can be offered as an exhibit.

(Document entitled "Railroad Commission Weighting

Method Applied to 1938 Rock Pressures by Counties," marked Exhibit No. 48 for identification.)

Exhibit No. 48 shows the details of the calculation of an average rock pressure calculated from the data which were the bases for Exhibit 12 by dividing the area by counties rather than by 50 pound pressure contour bands. There are ten counties. I believe there is one well in Sherman County which is not included on these averages. It is not certain whether it is a part of the field. As yet the Railroad Commission does not so consider it.

Going from left to right, the first column of this tabulation is the counties. The second is the number of wells within that county on which the Railroad Commission reported rock pressures as a result of their 1938 survey. The third column is the sum of the rock pressures reported for those wells by the Railroad Commission. The fourth column is the sum divided by the number of wells or the arithmetical average of the rock pressures reported by them for the wells in that particular county. The fifth column is the total acres lying within the particular county and within the boundary of the field. The final column is the product of the average rock pressure, which is the fourth column, by the total acres, which is the fifth column. The sum of those products as shown at the foot of the last column, 445,126,437, is divided by the total acreage, which is the total of the next to the last column, 1,475,324, to give a weighted average pressure of 301.71 pounds per square inch.

There are no wells in Oldham County. There is a little bit of acreage there, and we assigned to it the same average pressure as that of Hartley County.

Except for the fact that a different division into areas was used, this process is exactly the same process as that used by the Railroad Commission in arriving at their 337.66. The difference is that our areas were chosen by counties instead of by these bands of varying pressures.

260 If you could arrive at the ultimate equilibrium pressure by the means adopted by the Railroad Commission in arriving at that ressure of 337.66, using 50 pound bands, you should get the same result if you used the 20 pound bands that are reflected by Exhibits 21, 22, 23 and 17. It seems to me if one method of dividing areas would give a weighted average pressure which is the equilibrium pressure, then another method of dividing the area should give the same result. There should be nothing sacred from the

reserve standpoint about these 50 pound bands and the arithmetical average of pressures within them.

If you narrow the bands from 50 down to 20 and create more zones, as appears on Exhibit 23, I do not think you would come any closer to equilibrium pressure, but you should come closer to the true weighted average weighting on surface area alone. The smaller the area that is considered, the closer you should be to true weighted average on surface area alone; but you wouldn't necessarily be any closer to equilibrium pressure.

You ask if it were possible to get that result by taking bands of pressures, stepping up from low to high at intervals of 50 pounds, as was done on Exhibit 12. You should get that same result, if it be the right result, namely, the ultimate pressure equilibrium, by going up in steps of 20 just as logically as going up in steps of 50. My answer is that if that initial assumption, which I believe to be entirely incorrect, were made, it seems inescapable to me that conclusion would be true.

I have made such a calculation, stepping up the pressures by steps of 20 pounds, on the 1937 rock pressure survey. I used the 1937 survey because six or eight months ago I had done that for the entire west field for an entirely different purpose, and I used the 1937 rock pressure map, which is Exhibit 23. Since I have been in Chicago I have done the east field from that same map, and combined those results to give an average on 20 pound bands. There is another difference in that method of calculation too. Instead of using the arithmetical average on the rock pressures of the wells within the bands, I used the average pressures for the bands, which I consider more nearly correct. I did not use the absolute pressures, which would be still a little bit more correct. In other words, for the band reading from 400 to 430 I used 410, because the map I worked from in figuring the west field was contoured in that zone at even closer intervals.

With respect to my saying that it would be more accurate if I had used absolute pressure, if you average three and five you get an average of four but if you average three plus two—that would not work out. I may be wrong on that. I just have the impression—that works out it would be the same. I am mistaken on that. It would be a percentage variation, but I was mistaken there; I was not thinking straight.

I had taken Exhibit 23 and constructed from it for my own purposes a map which was contoured for the west field, not in pressures but in loss of rock pressure from original —that is, 430 on Exhibit 23 would correspond to zero on my pressure log map, 330 pounds per square inch would correspond to the 100 pound contour for pressure loss on my map. I had planimetered that map for an entirely different purpose and had that detail with me. What I did was to arrive at the weighted average pressure loss for the area, following the same principle that the Railroad Commission used in arriving at this 337.66, except that it was on 20 pound intervals of pressure instead of 50, and I weighted on acreage alone. I have prepared an exhibit showing the results of thus comparing the pressures and weighting them as to area.

261 (Document entitled "Panhandle Field, Railroad Commission's 1937 Rock Pressure Data Weighted By Acreage From Maps Contoured to 20 Lb./Sq. In. Intervals," marked Exhibit No. 49 for identification.)

That entire exhibit covers a determination of average rock pressure weighted by acreage from the 1937 rock pressure data on Exhibit 23. The first page, under the heading "A", covers the determination of this average for the West Panhandle gas field. As I stated this morning, this calculation is made from a map that I had prepared in my office contoured to loss of pressure from the original rock pressure. As you can see on this first page, the first column on Exhibit 49 shows the zone average pressure loss. The next column is the corresponding average rock pressures of those zones. The third column is the area in acres. The fourth column is the product of area and pressure. The sum of those products divided by the total acreage gives a weighted average of 350.19.

At the head of the second page is the Railroad Commission's weighted averages for the same set of rock pressure figures. Those figures were obtained from the 1937 and 1938 reports of the Commission. In their report the West Panhandle field is divided into sweet and sour gas, which I have combined, and which gives 367.71, or approximately ten pounds higher than the weighted average arrived at by my calculations.

Under the heading "B" on the second page is a calculation of averages for the East Panhandle field. These calculations were made during the last week in Chicago from the map, Exhibit 23, which is the 1937 pressure contoured at

20 pound intervals. That calculation leads to an average pressure of 272.59 pounds per square inch, as compared with the Railroad Commission's weighted average for the same data of 283.84.

On the last page, page 3, I have combined my figures to reach a weighted average pressure, weighted on acreage alone, of 335.58, as compared with the Railroad Commission's average of 347.05.

Using the method employed by the Railroad Commission, which weights the well pressures in areas of 50 pound pressure ranges, the same method of computing gives 347.05 pounds per square inch for the year 1937, whereas if you use 20 pound intervals for the same year, that is, during the same period, the result, instead of being the same, turns out to be about 11½ pounds lower. The average determined from the 20 pound interval map is about 11½ pounds per square inch lower than the one which the Commission determined, or 335.58 as against 347.05.

If you vary the method employed by the Railroad Commission, changing it from seven 50 pound bands to counties, but using exactly their method of computation, the 1938 comparison was 337.66 for the Railroad Commission as against 301.71 when you computed it by counties and used the same data. That is a difference of approximately 36 pounds per square inch.

If you make a computation of 20 pound bands instead of 50 pound bands, using the average pressures times acreage as your products successively as you go across the field,
you will not necessarily get any closer to the equilib-
262 rium pressure. As you subdivide into successively smaller units of area for a determination of that kind, you will get closer and closer to the true average, weighted on area alone. That is just the mathematics of the thing—as you subdivide into smaller areas you get a more precise thing.

If you did it for the field as a whole, your accuracy would not be as great as if you did it in 50 pound bands. If you do it in 50 pound bands, your accuracy is not so great as if you did it by 20 pound bands; and if you do it by 10 pound bands, you will get that much more accuracy. You would approach a more correct determination of the average weighted on area alone. But that would not necessarily be any closer to the correct equalized average which would be obtained if the field were shut in. The things are not necessarily related. That is where I went haywire this morning.

I misspoke myself and then got all balled up. What I meant to say was that a closer approach to the true average pressure condition within the reservoir would be made by using, rather than surface rock pressure, the pressures corrected to reservoir pressures by allowing for the weight of the column of gas in the well. You would get a truer picture because your ratio is greater off high pressure wells than low pressure wells, since there is more gas in the high pressure wells.

(EXHIBITS Nos. 46, 47, 48 and 49 for identification, offered and received in evidence without objection except as to EXHIBIT No. 48, which was received in evidence over the objection of counsel for each of the two commissions to whom the Examiner granted exceptions. Motion to strike reference to Exhibit No. 48 and portions of that exhibit which were read into the record or referred to denied.

Document containing calculations showing variations in withdrawals per pound drop in pressure on Railroad Commission's method of computing weighted average pressure, marked Exhibit No. 50 for identification.)

In applying the pressure decline method of computing reserves, if the correct pressure factor to be used in that method of computation has been ascertained, it is necessarily true that the withdrawal of the field per pound drop should be uniform during any period of the depletion of the field. There is one exception which comes in on very high pressure fields, where there is a deviation from Boyle's Law; but where the gas conforms to Boyle's Law that is necessarily true.

If the correct initial and terminal pressures for the period between July, 1935, to January, 1936, and the period from January, 1936, to July, 1936, were applied, the production per pound drop should be the same for those periods.

Having obtained the correct pressure factor, namely, the ultimate equilibrium pressure for any given time, and comparing that with the correct equilibrium pressure as of another time, and having ascertained the quantity of gas withdrawn per pound drop during that period, the same rate of withdrawal per pound drop should apply at any other period in the life of the field.

I have made a study of the volume of withdrawals and pressure decline in the Panhandle field to ascertain whether or not the situation obtained when I used the weighted aver-

age pressure ascertained by the Railroad Commission on acreage alone in the manner that they ascertained it.

263 Exhibit 50 was prepared by me and shows the calculations I have referred to.

It first sets out the source of the data used, and you will note an initial correction there of one number. It shows the calculation, the date, first, on which the pressures were determined by the Railroad Commission; the weighted average pressures determined by them as of those dates in pounds per square inch gauge; the corrected reservoir pressures corresponding to those averages in pounds per square inch absolute; the loss of reservoir pressure for each of those periods; the total quantity of gas, expressed in millions of cubic feet, produced from the field during that time, from the reports of the Railroad Commission, including casinghead gas; and, in the final column, the millions of cubic feet produced for each one pound per square inch loss in reservoir pressure during the particular period.

As you can see, those values in the table on the first sheet of Exhibit 50 range from 237,000 million to 484,000 million cubic feet of gas being produced, and then there was a gain in pressure as reflected by the Railroad Commission's files; and that the other three figures range from 43,000 to 54,000 million cubic feet per pound drop.

On the next sheet the first two periods which are given are combined to give the production in millions of cubic feet per pound drop for the period from July, 1935, to July, 1936, and those figures are compared with the other two periods, July, 1936, to July, 1937, and July, 1937, to July, 1938. They show a very wide variation. That, of course, shows merely as a test the inapplicability of those particular pressures to the calculation of reserves by the pressure decline method. It shows that those pressures are not applicable to the calculation of reserves by the pressure decline method.

(EXHIBIT No. 50 for identification offered and received in evidence without objection.)

Questions by the Examiner.

The gain in pressure was not a mathematical aberration of some kind. It was a true reflection of the increase in pressure weighted on the surface area. I don't think the coming in of new wells at high pressure was the cause of it. Just before that period there had been a tremendous

wastage of gas, and that wastage of gas had been stopped. That waste had resulted in some low pressure areas to the northeast, and when that tremendous wastage of gas at local spots was stopped, the wells located in those spots built up quite rapidly and gave an actual increase in the average by the method used by the Railroad Commission.

As to whether the figures used for each of the four or five intervals are comparable as to their selectivity or application or weight, I think that one of them is just as likely to be correct as the others. There is some uncertainty in the production figures for that first six months' period. The ultimate production loss figures on page 2, the last two, are identical with those on the first page. My earlier figures did not take into account any unreported gas. That would make the disparity much more, because, as you can see
264 on the second page, the greatest production per pound drop for the three years was from July, 1935, to July, 1936. Such unreported gas as was produced in quantity during this three year period was produced during that period. If it were included it would make even greater production than the 72,000 million MCF that is included by using only reported gas.

On page 2 of Exhibit 49 I show the West Panhandle sweet and the West Panhandle sour gas and give the Railroad Commission's average. The Commission divided the West Panhandle into sweet and sour. Their division on their page 11 is for the whole Panhandle, but there is no sour gas in the East Panhandle field.

The sour gas line runs into the border just south of the town of Pampa, which is some miles west of the dividing line of the East and West fields. I have simply weighted those two for purposes of acreage; that is, multiplied it by this acreage and divided it by the total acreage in the West Panhandle in order to get what I have called the Railroad Commission's weighted average for the West field. I tested that by making a similar weighting of the three divisions which are shown on page 11 of Exhibit 26. I tested that method of weighting by weighting the three divisions which are shown by the Commission, by the acreage of each, divided by the total acreage, and got a final result of 347.05, which is identical with the final weighted average pressure of the whole field. That would eliminate any question arising from my handling of it as I have done on pages 2 and 3 by another method. It shows that the method which I used there is the same.

The fifth column is the Railroad Commission's reported production for the period, including casinghead gas.

Direct Examination Resumed by Mr. Morgan.

I have tried to make a comparison between the volume of withdrawals per pound drop during the three one-year intervals—or rather they are not one year intervals—the three intervals of August 1, 1935, to January, 1936; January 1, 1936, to July 1, 1937; July 1, 1937, to August 1, 1938, using the same mechanics as were used by Mr. Brown in computing his estimates on what he called the pressure decline method, applying that to the Railroad Commission's weighted pressure, using area alone.

Mr. Brown, in applying what he called his pressure decline method, used total production up to July, 1938, which I believe was something over five trillion. The total production I used was six trillion, nine hundred billion; and the figure which Mr. Brown used as the withdrawal from the dry gas field was equal to that total production of approximately six trillion, nine hundred billion, minus six thousand times the total number of barrels which had been produced up to that time. I applied the same arithmetic for the three different periods of time, and prepared a tabulation showing the result.

(Document entitled "The Pressure Decline Method as Applied by Mr. Claude C. Brown But Using Various Intervals Instead of One Date", marked Exhibit No. 51 for identification.)

265 Exhibit No. 51 shows the details of that calculation.

Taking the first line across, the withdrawals from August 1, 1935, to January 1, 1936; during that period there was production out of the Panhandle field, according to the Railroad Commission's report, of 8,738,262 barrels of oil. Multiplying this number of barrels of oil by six, we arrive at an equivalent quantity of gas of 52,429,572,000 cubic feet.

In the fourth column is Mr. Peterson's figure for total quantity of gas produced during the period, which was 263,940,459 MCF. Subtracting from that quantity the 52 million odd that was calculated by multiplying the barrels of oil by six, I arrive at a figure of 211,510,887 MCF of gas, which is analogous to the five trillion figure used by Mr. Brown in his estimation. In other words, it is the

total quantity of gas produced, minus six times the number of barrels of oil produced.

In the next column I show the pressure at the beginning and end of the period corrected to absolute pressure at a depth of 2,618 feet.

In the next column we show the change in reservoir pressure during the period.

In the next column we divide the net quantity of gas, 211,510,887 MCF by the pressure drop of eight pounds to arrive at the MCF of gas produced per pound drop, which in the case of this first line is 26,438,861 MCF.

At the original rock pressure of 430 pounds per square inch gauge, the pressure in the reservoir is estimated to have been 471 pounds per square inch absolute. At 25 pounds per square inch abandonment pressure at the wellhead, the pressure at the reservoir is estimated to be 40 pounds per square inch absolute. Subtracting 40 from 471 gives a production interval, you might call it, of 431 pounds per square inch. 431 times production per pound drop in pressure gives the indicated original reserve to an abandonment pressure of 25 pounds per square inch gauge at the wellhead as 11,395,149,091,000 cubic feet of gas.

Unfortunately, we had to split the period into odd intervals because we didn't have the gas production figures broken out for July, 1936. We therefore have a first period of six months, a second period of eighteen months, and a third period of a year.

It should not make any difference if the correct pressure factor had been arrived at by the Railroad Commission. It should come out identical for any of those periods. It should come out the same for any of them, as it should for any time back of the beginning or between any of them.

The actual results expressed in estimating the original reserve under an abandonment pressure of 25 pounds
266 gauge at the wellhead ran from eleven trillion up to something over twenty-nine trillion. It was twenty-nine trillion plus for the period ending July, 1937, and 22 trillion 882 billion for the period ending August 1, 1938. In this computation I followed exactly the steps followed by Mr. Brown without applying a recovery factor.

(EXHIBIT NO. 51 for identification, offered and received in evidence without objection.)

Questions by the Examiner.

The figure of 11 trillion might be more in line with the 29 trillion if I had taken into account the wastage in the first period. That would tend to bring up the thing. What we were using here were Mr. Peterson's production figures, in which Mr. Peterson has attempted to make some correction for that wastage. If more gas were produced, it would bring it up closer in line.

Cross-Examination Interposed by Mr. Slaff.

By saying that the figures were not broken out for the period ending July, 1936, I meant no total had been brought out to that period. The production in Mr. Peterson's tables was not split in the table for the year. In Exhibit 50 I used the Railroad Commission's figures, which had monthly figures, which can be calculated to any of my dates.

Direct Examination Resumed by Mr. Morgan.

If the correct ultimate equilibrium pressure could be arrived at in the manner used by the Railroad Commission of Texas, if we assume that that method would give the right result, we would get the same results if we used 20 pound bands as if we used 50 pound bands. I expect the same thing would be true if we used bands of 5 pounds or 100 pounds, or any other size. This physical law gives no effect to the coloring on the map at all. You could use intervals of 10, 50 or 100 pounds, or you could use the whole territory, just as logically so far as the results you could hope to obtain would be concerned, and you would be just as likely to get the right answer.

I have been asked to explain the difference between the terms porosity and permeability as those terms are used in the profession. Porosity is simply a measure, expressed in terms of percentage of the bulk volume of the volume of voids or pores. That is, if we had a barrel full of buckshot, it has a bulk volume of 42 gallons of buckshot. We can pour into that barrel quite a lot of water. We can pour in enough water to fill up the voids, and we can probably pour in about ten or twelve gallons of water. Say that we could pour in ten gallons of water into our 42 gallons of

buckshot. Our porosity would be 10 divided by 42, or the porosity in that case would be approximately 24.8%.

We can distinguish, and do distinguish in the case of reservoir rocks, between total porosity and effective porosity. The analogy there would be to fill our barrel up with hollow glass balls. The total porosity in that arrangement would be very high because if we were to crush those balls down we would have very little solid material in them.
267 We might have a total porosity in such a case of as much as 99%, as we have in volcanic ash, or pumice stone, which is stone so light that it will float. However, in the case of this arrangement of glass balls, all the water that we could pour into our barrel would be enough water to fill the space between the balls, and that would measure the effective porosity. It would probably be on the order of 20% to 25%.

Permeability is something else. Permeability is a measure of the ability of a porous medium to permit the passage of fluid under a pressure differential. There is a strict analogy to permeability in the electrical field. In the electrical field we have conductivity and resistivity—conductance and resistance. One is the reciprocal of the other. Permeability is the reciprocal of the resistance of a formation to the flow of fluids, just as conductivity in electrical terms is the reciprocal of the resistance of a conductor to the flow of electricity. The term fluid means anything that will flow. It includes gas, oil or liquid.

Questions by the Examiner.

In response to the inquiry of whether when I talk about the permeability of gas I mean anything about the velocity with which the gas flows through, I will say that the thing applies as long as you have what is described as a steady or streamline flow. When you get into a turbulent flow your losses increase. The energy in an electrical system is thickly analogous. As long as there is a steady flow below the turbulent speed your loss is small. When you get into the turbulent flow you have losses which result in increased consumption of energy; but the electrical analogy would be strictly true as related to pressure conditions.

The time it takes gas to soak through a porous layer has nothing to do with the permeability because the only thing that makes it soak through is the pressure. Permeability does not vary with the pressure; it is the funda-

mental unit. Permeability multiplied by pressure is the measure of the velocity.

When you say permeability or impermeability, you take into account the frictional character of the substance which the gas is attempting to get through. Your friction results in low permeability, just as your I^2R in the electrical field, where your loss is higher in the conductor of electricity.

You don't have a permeability factor like you do a porosity factor. The fundamental unit of permeability is based upon the rate of flow of a fluid having a viscosity of 1 through 1 centimeter cube of porous medium, and it is called a Darcy.

268 The gas industry has not done as much as the oil industry in conducting tests as to the length of time it takes to pass through a porous substance. In the last few years the oil industry has been studying the permeability of the formations very thoroughly, and they use gas and air as the fluids for measuring those permeabilities. There has been an extensive research on that. They do that in an attempt to determine the extent of drainage. I would not say that no work has been done in connection with the drainage of gas, but there has been much less work done in connection with gas fields.

You inquire how much of a shift in position and change of color of those bands shown on Exhibit 12, is due to gradual encroachment or spread, or density of gas and oil wells in that area. I don't know. I have been attempting off and on for months to arrive at a conclusion which would satisfy me on that point. I have constructed zone maps showing as nearly as I can determine how much gas has been produced out of wells in various parts of the field, and I have worked up that information from pressure loss figures in an attempt to work out some means of computing how much gas has come from here and there, and how much pressure drop in any area has been caused by production out of wells in each area, and how much has been caused by drainage from that area to other areas, and I don't know the answer yet.

Direct Examination Resumed by Mr. Morgan.

From my knowledge of the Panhandle field, I think there is some rather consistent relationship between the quantity of gas in place and the potential open flow of the well. I think the assumption that the area in which a 40 million

foot well is located has twice the per acre reserve of the area where the 20 million foot well is located is the best presumption we can make of the relative per acre content at the present time. I don't suppose that it is rigorously or scientifically correct as to a couple of wells; but I believe on the average over the field it is pretty close to a correct relationship, and I think it is the best figure we have.

In the oil and gas business, where a new field is opened up there is always an inrush of the bold and speculative, trying to get in on the play. There is a partiality toward leases for sale in the vicinity of a big well as compared with those which may be for sale in the vicinity of a small well. The preferred acreage is that close to a big well, and it always commands a higher price than the acreage where the wells are small. This is based on experience that where you have big wells, there are the areas which make the greatest ultimate recovery per acre.

I have from time to time estimated reserves of gas in gas fields in connection with my practice. I have been using a recovery factor ranging from 80% to 85% most of the time in estimates I have made in recent years. Incidentally, most of those were on fields where the recovery conditions were more favorable than in the Panhandle. If I were going to make an estimate of the recoverable reserves as compared with the reserves in place in the Panhandle field, I don't think I would use a recovery
269 factor as high as 90%. I have not made an estimate of that field. I don't believe they will ever recover 90% of the gas out of the Panhandle.

In estimating recoverable reserves I have used abandonment pressures anywhere from 25 to 500 pounds per square inch, depending on the pressure in the field and upon what purpose the gas was to be used for. I have used pressures as high as 500 pounds in cases where the gas was being run into a pipeline without compression—that is, using the well pressure to force the gas through the pipeline. In that case the economics of that particular situation was such that only gas available above 500 pounds could be recovered. The matter of ascertaining the proper abandonment pressure in computing recoverable reserves is an engineering and economic question. I don't think the geologists know anything about it. For a particular use it is a question of the minimum pressure, and the minimum pressure rate of production to which the wells can be operated in the light of the entire situation involved. If I were

selling gas out of the Panhandle field to the town of Pampa, I could operate my wells down to a very, very low pressure because of its proximity to the field; but with a long pipeline we can't operate to anything like that low a pressure. It is a question of the economics involved in the affairs of the particular producer whose recoverable reserves are under consideration. It is a matter of the particular setup.

Cross-Examination by Mr. Booth.

I have made an estimate of the reserves in a natural gas field; but so far as I know, none of my estimates has been submitted in any proceeding before any administrative agency or court. I believe one estimate I made on one well was filed with the S.E.C. As far as I know, that is the only one of my estimates which was used for any such purpose.

I have never testified in any rate case. The estimates I spoke of were prepared on various occasions. I don't remember all of them now. Some of them were made in connection with proposed gas pipelines. Some were made in connection with valuation of properties for loan purposes; and some, I believe, were made more or less to satisfy the curiosity of oil operators who had leases for oil production and found out they had a lot of gas in the formation. None of those estimates was made in connection with the operation of Natural Gas Pipeline Company of America or Texoma Natural Gas Company. None of those estimates entered into the conclusions which were submitted in connection with my testimony today that I know of. They are a part of my general experience; that would be the only way.

As to whether I have testified before any regulatory commission on any phase of the subject such as I have testified to today, I will say I have testified in two cases as to the Panhandle. One of those was *Texoma* v. *Railroad Commission*, reported in 300 U. S., and the other was *Taylor* v. *A. & K. Petroleum Company*. That case had to do with metering and had nothing to do with any of these subjects.

I don't believe I have ever written any papers along
270 any particular line dealing with any general subject on which I have testified today, and I am pretty sure I have never furnished any reports to any technical societies.

I have not made any estimates of the reserves in the Panhandle field in any connection. I have made estimates in the Cotton Valley field in Louisiana, the Dickinson field in Galveston County, Texas, the Old Ocean field in Brazoria County, and a number of others I don't remember. They have been made for various clients. Within limits, I will supply further information concerning those estimates if you desire it. Of course, it was confidential work for a client. I can tell you what it was, etc. I could supply the names of the other places where I have made an estimate of reserves.

Redirect Examination by Mr. Morgan.

I have published a good many articles in scientific journals. I wrote a book called "A Report on the Petroleum Industry in the United States," which was presented to the Cole Committee of the House of Representatives, which investigated the oil industry in 1934.

Recross Examination by Mr. Booth.

That report was prepared for a group of clients, about fifty independent operators, who employed me to prepare it. It was privately published by the Gulf Publishing Company of Houston, which is not a subsidiary of Gulf Production Company but is an independent organization.

(Letter from the Chairman of the Railroad Commission of Texas to the Examiner, dated June 1, 1939, explaining that Commission's interpretation of the terms "casinghead gas" and "gas-oil ratio", marked Exhibit No. 52 for identification. Objection by Commission Counsel to the reading of the letter into the record sustained.)

(At this point the following discussion appears:

Mr. Booth: We have a witness. In view of the fact that the company has proceeded with the presentation of its evidence, and has indicated off the record that they are going to be ready to proceed again within a period of three or four weeks, I believe, it is my opinion at this stage of the case, that except for the presentation of this balance sheet of the company, that it would break up the logical presentation of the testimony in the case if we presented very much testimony.

I just want to clear up one thing. I understood Judge

Morgan to state that they were going to present all of their testimony dealing with reserves in the Panhandle field. Do we now understand, in order that we can prepare for cross-examination of the companies' witnesses, that this is all of the testimony you are proposing to offer? If that is not a fair question to ask, Judge Morgan, I will withdraw it.

Mr. Morgan: I don't know whether it will be all or not. It may be we will have some more testimony on redirect after the rebuttal testimony has occurred. That is all we have prepared at this time. We are trying to have an analysis made of this Panhandle oil as to its solubility. If we succeed in doing that in time, we will, of course, want to offer it, but that will not disturb the due order of the proceeding here in any way.)

271 JOHN M. WOODFORD, a witness for complainant, on being recalled, testified as follows:

Direct Examination by Mr. Booth.

(June 2, 1939.)

My name is John M. Woodford. I have previously testified in this case.

I prepared Exhibit 15. In checking it I found a number of typographical or other errors in the figures shown in that exhibit. Some were found by me and the company called my attention to some additional errors. Those corrections have been put in the form of an exhibit.

(Document entitled "Errata—Exhibit No. 15," marked Exhibit No. 53 for identification.)

Exhibit 53 is the correction sheet referred to. The errors on pages 6 and 9, lines 20, 39 and 31 are typographical errors. As to page 10, the company has notified me that the correct name of the Coltexo Gasoline Company was Coltexo Corporation. The mathematical figures on page 10 were purely an error on our part. As to page 11, which is statistical, I was notified by the company that there was a duplication in the year 1932 of some 150,000 MCF of gas used in 1931 by the company which has been included by us in the 1932 figures. The errors on pages 13 and 16 were typographical errors.

I have prepared balance sheets of the company, in the form of an exhibit, taken from the company's books for the years December 31, 1934, to 1938, both inclusive.

(Document entitled "Natural Gas Pipeline Company of America, Texoma Natural Gas Company, Balance Sheets Per Books At December 31, 1934 to 1938, Both Inclusive," marked Exhibit No. 54 for identification.)

Exhibit 54 is the exhibit referred to. It may be divided into three parts.

Page 1 is a balance sheet of Natural Gas Pipeline Company of America and is supported by page 2, being a statement of the plant and equipment. The figures are recorded on the books of the company at the dates stated without adjustment.

Page 3 is a balance sheet of Texoma Natural Gas Company, also supported by a statement of plant and equipment on page 4. The figures are also recorded on the books of the company as of the dates stated without adjustment.

Page 5 is a combined balance sheet of Natural Gas Pipeline Company of America and Texoma Natural Gas Company after eliminating intercompany investments and other items. Both companies maintain general ledgers in which are recorded specific accounts, to which accounts are posted monthly all transactions summarized in the companies' general journals and other supporting records. The balances remaining in these accounts at the end of each month are recorded in a book called
272 "Monthly Trial Balance Book." From these trial balances the companies prepare their balance sheets by grouping their accounts under various headings. The individual accounts for each of the years have been grouped in accordance with the grouping used by the companies in their 1938 balance sheet. The companies did not group the accounts uniformly in each year, and 1938 was taken by me as representing the latest basis used.

In all of the statements in the exhibit, the first column (a) is for the year 1934, ending December 31, and the remaining columns (b) to (e) are for the years ending December 31, 1935, 1936, 1937 and 1938.

Page 1 of the exhibit is a balance sheet of the Natural Gas Pipeline Company of America. Lines 2 to 6 show the balance remaining in the Plant and Investment ac-

count at book cost. The investments are Gas and Pipeline First Mortgage Six Per Cent Gold Bonds Series A, due December 15, 1946, of Texoma Natural Gas Company at par. Lines 8 to 18, inclusive, show the current assets of the company, included in which are notes and interest due from Texoma Natural Gas Company.

Line 20 represents the unamortized balance at the end of each year of the discount and expenses in connection with the companies' funded debt.

Line 21 gives the total of all the companies' assets per the books at the dates stated.

Line 23 gives the company's capital stock, 1,500,000 shares at a stated value of $2.00 per share.

Line 24 shows the funded debt of the company, which is a 15 year First Mortgage Pipeline and Collateral Six Per Cent Gold Bonds Series A, due December 15, 1946, issued in an original principal amount of $60,000,000, and in December, 1933, an additional one million dollars principal amount were issued. The company has reduced its outstanding bonds from $61,000,000 at January 1, 1934, to $46,500,000 at December 31, 1938.

Lines 27 to 34 show the current liabilities of the company, included in which are accounts, notes and interest payable due to Texoma Natural Gas Company.

Line 35 shows the balance remaining in the Depreciation Reserve account after charging to such account the proportionate part of property retired. This account is set up largely through corresponding charges to operating expenses.

Line 36 shows the excess of assets over liabilities and for the years 1934 and 1935 shows a deficit, and the remaining years show a surplus, which at December 31, 1938, was $918,791.50. The figures presented on this line agree with those presented in Exhibit 15, page 7, line 13.

273 Line 37 shows the total liabilities of the company and agrees with totals in line 21.

Page 2 is a breakdown by general ledger accounts of the company's plant and equipment, and the totals shown on line 16 agree with the figures on line 2 of page 1.

Page 3 is a balance sheet of Texoma Natural Gas Company. Lines 2 to 4 show the total balances remaining in the plant accounts of the company at book cost.

Lines 6 to 17 show the current assets of the company,

included in which are accounts due from Natural Gas Pipeline Company of America.

Line 19 shows the balance remaining of unamortized bond expenses, which is being written off over the life of the bonds.

Line 20 shows the total assets of the company at the dates stated.

Line 22 shows the capital stock outstanding, represented by 10,000 shares without par value.

Line 24 presents the funded debt, being Gas and Pipeline First Mortgage Six Per Cent Gold Bonds Series A, due December 15, 1946. There were originally issued $25,000,000 principal amount of these bonds, which are deposited as collateral under the trust indenture of Natural Gas Pipeline Company of America. Since issuance and up to December 31, 1938, a principal amount of $5,350,000 has been retired.

Lines 26 to 34 show the current and accrued liabilities of Texoma Natural Gas Company and included therein are notes and open accounts due Natural Gas Pipeline Company of America.

Lines 36 to 38 show the balances remaining in the depreciation and depletion reserves after charging to such accounts the proportionate part of property retired.

Line 39 represents payments received on account of the conditional sale of a gas well to the Coltexo Corporation, the terms of which sale were not carried out and in 1937 the balance remaining in this account was transferred to income account, as will be noticed in Exhibit 15, page 9, line 9.

The figures presented on Line 40 agree with those presented on page 15, line 7, of Exhibit 15.

Line 41, or the totals shown on line 41, agree with the totals shown on line 20.

Page 4 is a summary of the plant account by general ledger accounts and the amounts shown on line 19 are the same as those shown on line 2, page 3.

274 Page 5 is a combined balance sheet of Natural Gas Pipeline Company of America and Texoma Natural Gas Company after giving effect to elimination of the investments in Texoma bonds by Natural Gas Pipeline Company of America as well as the notes and open accounts between the companies.

There is also eliminated the amount of the transpor-

tation charges paid by Canadian River Gas Company to Texoma and then paid by Natural Gas Pipeline Company of America to Colorado Interstate Gas Company, which items offset.

(EXHIBITS NOS. 53 and 54 for identification, offered and received in evidence without objection.)

Cross-Examination by Mr. Morgan.

In the preparation of Exhibits 15 and 54 I dropped two years. Exhibit 15 covers 1932 and 1933, whereas Exhibit 54 leaves off those two years. There was no specific reason for dropping them, but our chief accountant suggested that five years would be sufficient. I have the figures for the other two years available.

I have been getting these figures for a year and a half. I don't remember just when I started work on this matter. I believe it was early in 1938, or it may have been around December, 1937. I had quite a crew of men working on the matter. We completed the work about the time the Federal Power Commission men moved in.

I have the other balance sheets including those two years. They were left out because our chief accountant said five years would be sufficient.

275 (June 26, 1939.)

(Document entitled "Panhandle District Casinghead Gas Report, July, 1932, J. M. McDonald, Deputy Supervisor," marked Exhibit No. 55 for identification.

EXHIBITS NOS. 37 and 38 for identification, offered and received in evidence without objection.

Letter from defendants' witness, R. D. Parker, to the Examiner, dated June 14, 1939, setting forth a list of cases in which said witness has testified since June, 1934, marked Exhibit No. 56 for identification. EXHIBIT NO. 56 for identification, offered and received in evidence without objection.

Letter from defendants' witness, J. D. Thompson, Jr., to defendants' counsel, dated June 13, 1939, setting forth a list of items of information which said witness was requested to furnish by counsel for the Federal Power Commission and the Examiner, including table showing completion dates of wells shown on Exhibits Nos. 32, 33 and 34 and data on gas-oil ratio of such wells, marked

Exhibit No. 57 for identification: EXHIBIT NO. 57 for identification, offered and received in evidence without objection.

Document entitled "Hughes' Method of Estimating Gas Reserves, Texas Panhandle Gas Field," marked Exhibit No. 58 for identification. EXHIBIT NO. 58 for identification, offered and received in evidence without objection.

Document entitled "Reference to Exhibit No. 42," showing the completion dates of certain wells referred to by defendants' witness, Hughes, marked Exhibit No. 59 for identification. EXHIBIT NO. 59 for identification, offered and received in evidence without objection.

EXHIBIT NO. 52 for identification, offered and received in evidence over the objection of counsel for each of the Commissions to whom the Examiner granted exceptions.)

276 MELCHIOR PALYI, a witness for defendants, testified as follows:

Direct Examination by Mr. Morgan.

(June 26, 1939.)

My name is Melchior Palyi. I have been living in Chicago since the end of 1933. I lived in London in 1933, and prior to that in Berlin, Germany. I was born in Budapest, Hungary. I obtained my final papers as an American citizen this month.

I received my college education in Hungary, and studied law at the University of Budapest. Then I started my business course in Germany, and had a business course in Frankfort and at the Munich business school and at the University of Munich. I got my Master's degree in business economics at the Business School of Munich, and my degree of Doctor of Political Science at the University of Munich. The degree in political science is more a general title covering the different social sciences. I specialized in economics and statistics. I specialized from the beginning of my study in money and credit.

Since I received my degree of Doctor of Political Science I have had partly academic and partly business positions.

In academic life I started as an instructor in Munich in 1918, and was appointed professor at the Universities of Goettingen and Kiel, and then at the graduate school of commerce in Berlin, where I became a professor in 1929.

I was invited to England in 1933 as lecturer at the University College of Oxford, and came to the University of Chicago as a visiting professor, beginning with January, 1934. Since 1937 I have been a research economist at the University of Chicago.

I have had other connections than my position of research economist at the University of Chicago during my residence in Chicago. I combine most of my time in academic and business work.

I started during the war in the external service of the Hungarian Ministry of Agriculture, and then of the Austro-Hungarian National Bank. Then I had a year's training in a western German commercial bank. Later, in 1928, I became chief economist of the Deutsches Bank. In 1931 I became the advisor, scientific advisor, of the Reich Bank, which is the central bank of Germany.

After I came to this country I was for a year connected with an investment advisory firm, and since early in 1937 I have been consulting economist to Stifel, Nicolaus & Company, an investment banking house, of St. Louis and Chicago.

277 The investment houses with which I have had connections recently are Stein & Roe, in Chicago, who are general investment advisers handling portfolios mostly of private persons, and Stifel, Nicolaus & Company, which specializes in municipal bonds. I was with Stein & Roe in 1934.

As to the phases of economics and monetary matters with which I have had occasion to connect myself in the course of my business and professional background, for twenty years I have specialized in money, banking and finance, especially along three lines. One is the theory and history of money and coinage, including problems of precious metals. Another is central banking, with which I have been also connected in a practical fashion and in which I made a close study of inflationary experiments, paper money inflations in Europe. I went through personally three major inflations and studied several others, and was incidentally also a member of the committee of the German federal government in 1922 and 1923, which had the job of working out a program of stabilizing currency

during the inflation. That was a second field. The third one is banking, commercial and investment banking, in a technical sense, in different aspects of it. For example, I wrote studies about bankers' balances and international capital movements, and also about mortgage banking. I have published a comprehensive encyclopedia on banking in Germany, covering the field.

I have with me a list of my English as well as my German publications, with the titles translated. Those publications are as follows:

I. Books and Pamphlets:

1. Monetary Chaos and Gold. The University of Chicago Press, Chicago, 1934. 26 pp.
2. Principles of Mortgage Banking Regulation in Europe. The University of Chicago Press, Chicago, 1934. vii—38 pp.
3. Liquidity. Minnesota Bankers' Association, Minneapolis, 1936. 23 pp.
4. The Chicago Credit Market. The University of Chicago Press, Chicago, 1937. xvi—448 pp.
5. Life Insurance and the Financial Frontier. Reprint from Journal of Business, University of Chicago, Vol. XII. Nos. 1 and 2, Jan. and Apr. 1939.

II. Articles in Periodicals, etc.:

1. "Adam Smith on the Continent." In the symposium on Adam Smith published by the University of Chicago, 1927.
2. "Internation Capital Movements." Encyclopedia of Social Sciences. (N. Y.)

278 3. "International Aspects of Problems of Production and Trade." The American Economic Review, Vol. XXV, No. 1, Supplement (March, 1935), pp. 45-62.

4. "Prospects for Inflation." (The University of Minnesota Press, 1936), pp. 12-18.
5. "The Liquidation of an Induced Prosperity." Pamphlet published by Stifel, Nicolaus & Company, Inc., Chicago, Oct. 1937.
6. "Bank Portfolios and the Control of the Capital Market." Journal of Business, University of Chicago, Vol. XI. No. 1. Jan. 1938.
7. "Present Federal Reserve Policies." Journal of Farm Economics, Vol. XX. No. 1. February, 1938.

8. "Inter-Bank Balances." Pamphlet published by Stifel, Nicolaus & Company, Inc., Chicago, March, 1939.
9. "Why Gold?" Pamphlet published by Stifel, Nicolaus & Company, Inc., June, 1939, Chicago.
10. "Is the Liquidity of Banks a Hindrance to the Rate of Prosperity?" 1934 Group Conferences, Illinois Bankers Assn., pages 22-30.
11. "Open Market Policy and Totalitarian Control." The Review of Politics, July, 1939.

III. Book Reviews and Minor Publications:

1. Numerous Book Reviews in the Journal of Political Economy, the American Journal of Sociology, the Journal of Business of the University of Chicago, Journal of the American Statistical Association, etc.
2. Numerous Minor Pamphlets published by Stifel, Nicolaus & Company, Inc., Chicago.
3. Shorter Articles in Magazines and Newspapers—Manchester Guardian Commercial, Daily Telegraph, The Financial Post (Toronto), etc.

Dr. Palyi's Publications in German.
(Titles Translated.)

I. Books and Major Pamphlets:

1. The Monetary Theory of the Romantic School. Dissertation, Munich, 1916.
2. The Political Theory of Money. (1922.)
3. International Capital Movements of the Post-War Era. (1926.)
279 4. The Balance of Payments of the United States. (1929.)
5. The Economics of Gambling. (1929.)
6. Encyclopedia of Banking. (1932.)

II. Major Articles in Scientific Periodicals and Symposiums.

1. The Economic Organization and Foreign Trade of Soviet Russia. (1922.)
2. What is Inflation? (1923.)
3. Unsolved Problems of Monetary Theory. (1925.)
4. Capital Movements and the Balance of Payments. (1926.)
5. The New Agrarian Revolution in England. (1926.)
6. A Century of Prices and Real Wages. (1928.)

7. The Problem of Inventories. (1929.)
8. Financing the Reparations by Foreign Loans. (1928.)
9. Central Banks and Commercial Banks. (1930.)
10. Historical Survey of the Theory of International Trade. (1930.)
11. Coinage and Paper Money. (In the German Encyclopedia of Social Science, 1931.)

III. Dr. Palyi was Editor of the following German Works and Periodicals:

1. Max Weber's "Economic History." (1923.)
2. "The Present State of Sociology." Symposium, two vol. (1924.)
3. "Post-War Economics, Theory and Policies." 2 vol. (1925.)
4. Series of Economic Textbooks published by J. Springer, Berlin, 1928-32.
5. "Monetary Economics." Monthly publication of the Institute of Currency Research, Berlin, 1932-33.

IV. Numerous short articles and book reviews in scientific periodicals, financial magazines and daily newspapers.

As concerning Natural Gas Pipeline Company of America and Texoma Natural Gas Company, I was asked to
280 make a study of the factors which were likely to influence the general price level and the level of costs affecting those two companies within a period of, say, thirteen years. I commenced that study about a year ago. I have been working on it, with interruptions, for eleven months.

The general price level is determined by a number of factors, among which the most important, and those to which I have given particular attention, are, first the gold production and gold reserves; second, the credit volume in this country and abroad; third, the velocity of circulation of money and of bank deposits; fourth, governmental policies affecting the monetary and credit system directly, such as devaluations or revaluations, and credit policies, including budgetary deficits or balanced bugets, and similar things.

Furthermore, factors on the side of the production of goods, commodities, such as technological progress, volume of production, and results of general policies, not particularly monetary policies, but general policies, ranging from

national policies in the field of labor and other fields to international policy, such as war and peace.

With all reservations one has to make in one's price predictions and such things as future price trends, I made the attempt to evaluate and estimate these different factors, and came to the conviction that the period of fifteen years is long enough to make it strictly probable that a major rise of prices is most likely to happen.

Discussing first the question of monetary gold reserves, may I start by saying that we are living in a world in which the monetary systems of the leading countries are based on gold, and that the volume or size of the gold base is a very important factor in determining credit volume and thereby the volume of purchasing power of each individual country. The volume of gold available for monetary purposes has risen in an extraordinary fashion.

The rise of gold production started after the war in 1922, was accelerated somewhat in 1926, and then took a rapid pace about 1930. Between 1929 and 1939 the annual gold production in ounces doubled. The annual worth of gold production in terms of dollars, due to the devaluation of the dollar, trebled. By devaluation of the dollar, I mean, of course, the change in the gold content of the dollar; that is, the fact that instead of minting some 20.7 dollars out of one ounce of fine gold, gold of standard fineness, since February, 1934, the American mint is supposed to mint 35 dollars out of the same quantity of gold. That was a proclamation of the Federal Government changing the content of the American dollar early in 1934, so that an ounce of gold today represents 35 dollars instead of 20.7 dollars.

With respect to the increase of the annual produc-
281 tion of gold, I will state that the increase in the twenties was minor and largely accidental. It took place largely in South Africa. The reason was that the gold ore deposits in the Rand Mountains, which belonged to the South African government, had not been exploited before for bureaucratic reasons. It took a long time before mining got under way. There was, however, a minor increase in the twenties only. The major increase in the thirties is largely due to the depression and the devaluations. The depression lowered the general price level all over the world. The devaluation raised the number of monetary units which are mined out of an ounce of gold. The two together had the consequence that gold production became

much more profitable. The gold producer, who pays practically the same wages to labor, or in some countries even lower wages than before 1930, receives a higher price in dollars or pounds sterling for his product.

In addition, his product commands a greater amount of commodities and services in the markets of the world. His purchasing power rises, both in money terms and, in addition, in goods terms.

Therefore, a great incentive has been given to gold production, with the result that gold production has been stimulated all over the world. Old mines, or so-called marginal mines, marginal shafts, which have not been used before, have been opened or have been restarted again. New fields have been discovered, especially in Russia, in Australia, western Australia, New Guinea; to a lesser extent in Japan, China, Brazil, and also in Canada gold production has been stimulated. Furthermore, technological progress has been applied to a greater degree to gold mining and dredging, since it is remunerative to do so.

The net result of all this has been a rise in the annual production of gold, which I mentioned. The annual gold production amounted in 1929 to nineteen million fine ounces, and in 1938 to 36.7 million fine Troy ounces. It has practically doubled. The growth was from 19 million to 36.7 million ounces, which is an extremely unusual rise in gold production, and only paralleled in modern history in similar lengths of time during the nineties and at the beginning of the century; that is, shortly after the discovery of the Transvaal mines.

Most of this increase in the supply of monetary gold comes from Russia, Canada, the United States, and Australia, together with New Guinea. South Africa used to produce in the twenties half of the world's annual output. Now it is only responsible for one-third of the annual output. Its production has risen only slightly. The increases are in Russia, the United States, Canada, and the other places I have just enumerated, and were due to the causes which I have just mentioned.

Another substantial source of monetary gold supply has been in the last six or seven years the eastern gold hoards.

India and the rest of the Far East used to hoard gold
282. and used to absorb annually, for example, in the
1920's, on the average something like 70 million dollars worth of gold which went into private hoards of all

kinds. From 1932 until 1939, about one and one-half billion dollars worth of gold came from these sources to the world markets because of the rise in the gold price in terms of pounds sterling, and combined with the fact of unfavorable balance of trade in India and China, and with the lack of British capital flowing into those countries, induced or compelled the Indians and Chinese, and so forth, to give away major or minor parts of their gold hoards, and so the very unusual thing happened—very unusual in the entire history—that such an amount of gold reappeared which was supposed to be buried forever in those eastern hoards, and reappeared on the London gold market and went into monetary uses.

Furthermore, a minor addition to the monetary gold supplies came, curiously enough, from the so-called industrial use of gold, from the arts, which formerly absorbed a minor portion of the annual gold output. Since the depression the process has been reversed. Instead of absorbing gold, the arts gave back gold; that is gold in the form of ornaments or other forms has been melted down and returned into the monetary systems. This was partly due to artificial political measures, such as in Germany, Italy, and in similar countries, and, as in Poland, where the appeal was to the patriotism or other motives to make people hand back even their rings and other ornaments to the government. Partly as a consequence of the depression, gold in the form of jewelry lost value. Gold in the form of coins, that is, of money, gained value. purchasing power, so it became remunerative to turn the gold from the industrial into the monetary use.

The normal amount was, for example, in 1929, 25 million gold dollars, which was taken off the annual output for non-monetary use of this country in 1929. In 1934, which was a record year of back-flow from industry into the monetary use, that back-flow in this country alone amounted to 62 million dollars in terms of the new dollar.

I have prepared a graph or chart, showing the annual growth of the monetary gold supply. It covers the period from 1926 to 1938, inclusive, and shows the total addition to world gold supply, the South African production, the other than South African production, the changes in eastern hoards, and the flow into and out of industrial use in the United States.

(Document entitled "Sources and Annual Growth of

Monetary Gold Supply (1926-1938)," marked Exhibit 60 for identification.

Document entitled "Annual Growth of Monetary Gold Supply in the World, 1926-1938," marked Exhibit 61 for identification.)

Exhibit 60 shows that from 1926 the total addition to world gold supply, that is, production plus addition from other sources, has risen from about 18 million ounces a year to about 36 million ounces a year.

The most important part of these supplies consisted of what is called on the chart "Other World Production," which accounted in the first year for about half of the total addition and in the last year for about two-thirds. South African production was about one-half of the total world production in the first year, but has only risen 283 by about two million ounces in the twelve-year period, so that its role at present is much slighter than it used to be—its apparent role, I should say.

Eastern hoards appeared for the first time in 1931. 1932 was the year of the greatest amount of addition from that source to the monetary gold supply. From then on the contribution of the Far East and of India declined.

A minor amount is represented by the curve "Industrial Use," which until 1931 meant a diminution of the world money supply. That amount was taken off every year, an amount averaging something like one million ounces. From 1931 on, with the peak in 1934, the industrial use, as I mentioned already, adds to the annual gold supply for money gold purposes.

Prior to 1931, the eastern hoards would have been negligible. They are shown in what I call a flow-out. I did not have the precise figures about them, so I did not put them in. It is a little difficult to find out how much gold the Hindus and Chinese and these Orientals put in circulation. The figures on eastern hoards from 1931 on are very precise figures, because they represent the outflow from India, China, Egypt, the Straits Settlement, to the London gold market.

Cross-Examination Interposed by Mr. Slaff.

Exhibit 61, merely gives the data and the sources from which Exhibit 60 was compiled, except that it adds one factor that is not shown on Exhibit 60, the last column

representing the total monetary gold reserves in central banks and treasuries. That is a factor I intended to mention later on and which I put in the same table for the sake of convenience.

I haven't the figures showing the Oriental hoards for the year 1938. As to the flow-out for the years 1937 and 1938, the Director of the Mint has zero for 1937—that is, no flow-in or flow-out—and for 1938 I have not seen the figure. The figure for 1938 is not yet available because the report of the Director of the Mint is not out yet. The latest figure I have seen was zero, which means plus or minus or an amount so small that it is practically zero. I have no objection to adding that to Exhibit 61.

Of course I have not the figures here, and therefore it is not authentic, but I am saying this from memory. The reason I did not put it on is probably because I did not have the figure reliable enough. I can review that figure when the Director of the Mint comes out with the report in June, which will be in a few days, and I can easily procure that figure for 1937 and possibly for 1938. I would like to verify it from the new report.

(EXHIBITS 60 AND 61 for identification, offered and received in evidence without objection.)

Direct Examination Resumed by Mr. Morgan.

As to whether, in my opinion, the production of monetary gold at the present rate will continue, increase, or decrease over the next twelve or fifteen years, my judgment is that the future supply of gold is a question
284 which cannot be answered with absolute certainty, but for the most important single mining source, for South Africa, very good knowledge is available. The estimates are that South Africa can maintain the present rate of production for at least about twenty years to come. As to other countries, the knowledge of the sources of production is less definite; but, on the whole, for example, in the next important countries like Canada and United States—important for gold production—it is also pretty well known that for a number of years the present rate of gold production could be maintained. On the whole, there is no reason to believe that the gold ore reserves of the world that would be available would not be

sufficient for at least another ten years for the same amount of annual production as at present.

Furthermore, there is one more factor in the situation which I did not yet mention, namely, the South African production policy. In 1932-1933, under the pressure of the South African government, the leading mining interests, the five big corporations and the few minor ones in South Africa got together and agreed on a so-called conservation policy, according to which they are not using at present, since that date, their so-called high-grade ores. They only produce gold from low-grade ores. Just as a figure to indicate this, the average gold content of the ore produced in South Africa has declined very substantially in these years, namely, from 5.844 pennyweight per ton of ore milled, which is abbreviated Dwts., in 1933, to 4.460 pennyweight in 1937, the last year for which I have figures. In other words, the quality of the ore which they use is 20% lower now than in 1933.

The reason for this policy is that they figure at the present cost of production, which is slightly lower than in the twenties, and at the present high price in money terms for gold per ounce, they get sufficient for their gold product to make it worth while to produce the low-grade ore. If, for example, the value of the pound sterling—they sell always to the London market and count in pounds sterling—should go up again, the gold content of the pound sterling should go up in the future, then it would not be worth while in the future to produce the same low-grade ores, and, therefore, they preserve the high-grade ores until such time to come when it may not be remunerative to attack the low-grade deposits. Consequently, the conservation policy, from the point of view of the question asked me, amounts to a building up of future reserves.

As to whether in mining the low-grade ore they have to get out the high-grade ore too, with the result that they are loading part of the future cost of production on to this in addition, I will state that in mining the low-grade ore they do not get out the high-grade ore too. They are in different layers. They choose the layer in which they operate. However, I am afraid I am not much of a mining engineer, and cannot express myself very technically on it.

In consequence of the circumstances I have stated, I do

not believe there is any major risk of a decline in
285 gold production for a substantial length of time to
come, unless very radical measures are taken, such as a revaluation of the pound sterling and the dollar to somewhere around their previous gold content, and at the same time a substantial rise in the cost of production of gold, which would make it absolutely unremunerative to produce most of the gold presently produced. Personally, I do not believe that such radical measures would be taken or even contemplated by any government, unless to offset a very substantial rise of prices, but then the rise of prices would have occurred already, and it is a question whether such rise would occur or not.

The history of government policies concerning the devaluation and then the reviving upward of gold is that devaluations, or what they used to call depreciations of currencies, occurred many times in history. The coin was clipped or otherwise its precious metal content diminished many times in every country. In modern times it did not occur in the 19th century. It did not occur here or in England. In England, as well as in this country, they went off the gold standard and permitted a depreciation of paper money in circulation in war times, such as the Civil War, the Napoleonic Wars, and the World War; but in Great Britain since 1715, when Isaac Newton introduced the foundations, as Master of the Mint, of the present gold standard, no devaluation for other than war periods occurred previous to 1931, or for over 200 years. But rare as such devaluations are, revaluations in the opposite direction, raising the gold content of the currency, are still more unusual, or occur still more rarely.

Minor efforts have been made by modern governments to revalue the gold content or increase the gold content of the monetary unit. For example, Great Britain revalued her pound sterling by about 5% between 1919 and 1925, when she returned to the gold standard, but those are very minor and do not affect substantially the general price level or prosperity, and even that created terrific political trouble in the country. Major revaluations practically never occur, and never have occurred, so far as I can recollect from my own studies, since the days of Queen Elizabeth, and there was only one example of a major revaluation in Europe and that was the Czechoslovakian experiment in 1919, when finance minister Rasin, who in-

herited, of course, from the Austro-Hungarian monarchy their monetary system, tried to re-establish a new currency by raising substantially, I think, some 25% or so the gold content of the circulating paper money. He got away with it, but they shot him. And that is the only case I can recollect in the last 250 years.

That is not a very good precedent to cite to the powers that be. I do not know any movement in this country or in England of any importance or size, except a few academic individuals, who would advocate at present the substantial revaluation of the pound sterling or of the dollar, while very substantial movements exist which advocate further devaluation. The price trend when the Czechoslovakian experiment was tried was a rising price trend—a post war rising price trend. In the depression Rasin would never have made the attempt.

286 Passing now to the relation of gold and the annual increment of monetary gold to price tendencies, in the normal course of events, of course, the effect of increasing gold supply on prices is not a direct one. The direct effect under modern conditions when gold does not circulate and when many times the volume of gold circulates in the form of credit money, such as paper money or bank deposits, the direct effect does not amount to much except to the extent that the gold producing countries become richer and more prosperous and thereby represent greater demand for international commodities.

In South Africa, for example, a great wave of prosperity exists at present. 75 to 80% of the annual exports consist of gold. In Canada, 20% of the last year's exports consisted of gold. So far as these factors go, they are a direct but very unimportant influence on the general price trend. The important tendency of influencing prices is through the indirect one of affecting the credit system. The credit system in each major country at present—I shall have an opportunity, perhaps, to discuss the countries and possibilities where that is not the case—is based on gold; that is, the influx of gold automatically expands the currency basis and the credit system, either in the form of more notes put into circulation or more bank deposits put at the disposal of the deposit owners who, in turn, can dispose of the notes or deposits for purchasing commodities or services, which in turn represent the rising

purchasing power and cause the subsequent tendency toward raising prices.

The increase in the monetary gold supply brings about the results I have stated in this way: Referring to this country, what happens is this: suppose somebody from London makes a deposit in a New York bank. He has to make it in dollars. The dollars are not available on the London market, consequently he has to send gold over. The gold on arrival is deposited by the New York bank in the Federal Reserve Bank of New York, which hands it over to the Treasury, which in turn buries it in Fort Knox, Kentucky. The Treasury hands over to the Federal Reserve a gold certificate, which represents a gold reserve of the Federal Reserve. The bank receives a deposit, a balance, at the Federal Reserve. That balance is as good as cash, as legal money. The situation now is, after the receipt of that deposit, the New York bank has an obligation to a customer, say, in London, and at the same time has the same amount on deposit with the Federal Reserve. The New York bank is under legal obligation to keep at present 22½% legal reserve for the $100 deposit; 77½% are free, so to speak. The New York bank may want some additional so-called excess reserve, say, another 22% or 25%, or a similar amount, but that still leaves the New York bank this 50% of the one hundred dollars deposited with it available for whatever purpose. If these deposits grow, the New York bank is likely to feel that it has to do something with them, according to the market situation, or the capital and money market, according to circumstances, and to the value of such deposits it will sooner or later lend money or buy bonds, which amounts also to lending money, and thereby put the money into circulation.

In short, at least a substantial part of that deposit
287 will sooner or later become a volume of purchasing power, an amount affecting the demand for something in the country. If it buys securities, the seller of the security will in turn receive a deposit and will be in the same situation as the bank was before. He will either deposit with another bank or the same bank, or will himself buy something, such as a security, until in the long run, at some point, to some extent, somebody is going to buy commodities with a substantial part of that money.

We have received in this country something like ten

billion dollars worth of gold since early 1934—roughly, ten billions. It is a little more now, approaching eleven billions. This amount is represented by deposits in the commercial banks of the country, almost entirely check deposits. Those deposits, half of them or more than half of them, permit the banks to give credit and thereby to add further to the deposit volume of the country. In other words, the influx of gold does not only automatically create deposits, but also permits the creation of more deposits in so far as the banks proceed to use the additional lending power which the free part of the deposited money gives them for expanding the credit volume. Credit expansion—that is the short result—is the necessary consequence under all the circumstances of a major and lasting gold influx.

I am speaking of the present situation of the 1930's. In the normal situation, money coming in and deposited with the banks is quickly used. That is, the banks do not keep major excess reserves which amount at present to over four billion dollars. They represent out of the ten or more billion dollars of total reserves with the Federal Reserve banks some four billion or so, which are excess reserves. This is a very abnormal situation as compared with the twenties. In the 1920's the American bank system as a whole had no reserves at all. It operated on a margin of credit borrowed from the Federal Reserve system. At present the banks do not borrow at all from the Federal Reserve system, but deposit four billion dollars more than they should deposit, according to legal standards, which legal standards have been doubled since the depression. On the whole, therefore, we live under very extraordinary circumstances compared with the twenties. Our potentialities of credit expansion have been cut down very substantially, and in addition the banks are very reluctant, as is everybody else, to make use of their funds.

Questions by the Examiner.

The legal reserve requirement for a check deposit was not quite doubled. It was 12% until 1933, and until 1936, as a matter of fact, and that has been double to 25%, and now it amounts to 22½%. That is not quite double. I just roughly said doubled. The Banking Act of 1935 permits changing the legal reserve requirements for commercial

bank deposits in a range from 100% of the previous reserve requirements to 200% of that requirement.

I am using so many figures by heart that I am not precise. 13% was for the Central Reserve city banks. The legal reserve requirement before the Banking Act of 1935 was 13% for check deposits and 3% for savings deposits. The maximum up to which it can be raised by the Board of Governors of the Federal Reserve system is now 288 6% for savings deposits and 26% for check deposits.

Actually it amounts now to 22½%, I think, for check deposits, and, I think, 4½%, if I am not wrong, for savings deposits.

The increase of reserve requirements was based on the idea that since a discount policy ceased to operate, and we are living in an era of allegedly permanent cheap money—at any rate it is permanent for the time being—the discount rate cannot be effective if it is raised, and therefore some other method should be put into the hands of the central bank to check on an expansion of the credit system. Therefore, in 1937, when an expansion got under way, the Board of Governors of the Reserve system decided that they ought to check it, and in several steps, from 1936 to 1937, gradually doubled the reserve requirements. Then came the recession of 1937, upon which they decided that they would lower it a little again.

Direct Examination Resumed by Mr. Morgan.

You ask for the meaning of the term "legal reserve" in the banking world, and inquire whether, if a bank had a million dollars on deposit formerly, it had to retain in cash or call deposits at least $130,000, or 13% of that, and could lend the balance of that million dollars. It had to retain that amount in the form of a deposit in the Federal Reserve bank of its district. It was at liberty to lend out and extend credit for the rest. That ratio has now been raised and the amount available for extending credit accordingly diminished.

We still have an excess of inactive deposits in the banks under present conditions. I account for that in this way. The great excess available at present is due on the one hand to the influx of gold. I mentioned the fact of a ten billion dollar influx, or more than ten billion by this time. My figures refer to April, and we have had a tremendous

influx in the last three months. This, plus the amount due to the gain, or so-called gain, in the value of gold by devaluation inside of this country, and some amount due to the money printing, to put it shortly, by the government. In short, it is due on the one hand to more money coming in to the banking system and expanding the currency basis, and, on the other hand, it is due to the fact that the banks do not use it, and your question boils down, therefore, to this: Why don't the banks use this excess?

They do not use it because, in a depression and under given circumstances, they are either reluctant to give credit or do not find what they regard as proper prospective borrowers for the credit which they would be willing to give. A non-expert way of expressing it would be to say the banks are afraid to loan to the man who has nerve enough to borrow under such circumstances as we have now.

On the whole, there is very little demand for credit of the kind which is regarded as a good risk from the bank's point of view, and this is due to the diminishing profit expectation on the part of the entrepreneur, on the part of the business men. There is a diminishing expectation of profit due to a number of factors, external and internal;

external, such as war prospects, a decline of interna-
289 tional trade, and the prospects of further decline;

internal, such as labor troubles and similar burdens on the minds of the persons who would be otherwise the prospective entrepreneurs and borrowers.

If the major inhibitions to enterprise which presently interfere with business activities, especially with the investment of capital in new ventures, would be eliminated —and personally, I think, though I cannot prove it, of course, that the external inhibitions are more important than the internal inhibitions in their general effect—we would find ourselves in an extraordinary situation. We would find ourselves with gold reserves and potential possibilities of credit expansion on hand as we never had in history. In the late 1920's we operated on a gold base of some four billion dollars. We would operate now on a gold basis of some 16 billion dollars or more.—In the 1920's the Federal Reserve system had not gone very far in expanding credit, but still the credit extended by the Federal Reserve system amounted to some 120 to 140 per cent of the system's gold reserves. At present the credit,

which the system has given only in the form of government bonds owned by the system, amounts to a small fraction of its gold reserves. In other words, the system could go on and give four or five times more credit to the banks than it has now in circulation. The banks in turn could go on and expand credit four or five times on that basis, even with the present legal reserve requirement. It would be a possibility of fantastic credit expansion and the problem would be how to check it rather than what expansion could take place.

With respect to the 1937 data embodied in Exhibit 61, I wish to state that I had no opportunity to check on it during the recess; but I am pretty sure the reason why I did not have the 1937 figure for industrial use of gold is because the Director of the Mint publishes his annual report always in June for the previous year, and does not yet have in June the previous year's figures for that item, so the latest available report, that of 1938, has not the 1937 figures. They will come with the 1939 report. That is the regular procedure. They are nearly two years behind. The data on industrial use are collected all over the world on a calendar year basis, and it takes a long time until the Director of the Mint gets from the American consular agencies from every country their reports from their respective countries showing what happened, how much gold has been consumed and for which purpose, in each country. For instance, you get the 1936 figures out of the 1938 report. The exhibit states in a footnote that the figures for industrial use were taken out of the annual report of the Director of the Mint for the fiscal year ending June 30, 1937, and that is the report which is published in 1938.

(Document entitled "Member Bank Reserves and Related Items—Ratio Chart (In U.S.A.)," marked Exhibit 62 for identification.

Document entitled "Gold, Money in Circulation, Deposits, Etc. In U.S., 1879-1939," marked Exhibit 63 for identification.)

Exhibit 62 was prepared by me. The chart on Exhibit 62 is drawn on a logarithmic scale. It indicates from year to year changes in percentage terms, that is, the percentage change from one year to the other on each of the four curves. The purpose of that chart is to show especially that the volume of money in circulation, plus net

deposits, moved fairly parallel with the gold stock of the country.

290 With the gold influx, deposit volume rises. Major gold loss is accompanied by a decline of the deposit volume or of the volume of money in circulation, respectively, or the sum of the two. The reasons for this we have discussed this morning. Gold, being the basis of the currency, the influx of gold automatically causes expansion of the currency system, including the deposits.

By net deposits I mean the total deposits minus bankers' balances, because counting bankers' balances would amount to a double count. The deposit of one bank in another bank is a redepositing of the deposits which are already deposited in the first bank. Their elimination is the usual procedure for certain purposes.

You will see on the chart that from 1934 on there is a very rapid rise in percentage terms of the gold stock taking place, or rather, from 1933 on. The deposit volume does not move upwards to the same extent. The reason is that this gold stock is figured in dollar terms, which means that it includes the valuation gained on the four billion gold reserve we had in this country before the devaluation.

Most of the devaluation gain, however, is still kept in reserve and has not yet been used for expansion of the credit system. 1.8 billion are in the stabilization fund, and some four to six hundred millions of so-called free gold in the Treasury, which is just about the difference between the rise of the gold stock and the rise of the deposit volume.

You also notice that the reserve balances, that is, the balances of banks deposited with the Federal Reserve Bank, moved almost exactly parallel to the gold stock, for the reason of that automatic correlation between the two which I discussed this morning.

The conclusion to be drawn from this is that further rise of gold reserves would carry into greater volume of deposits and currency in circulation. Of course, also, a decline of gold reserves would cause contraction of the deposit volume. However, as to the latter point, it may be remarked that the decline in the deposit volume does not necessarily follow the outflow of gold, because reserve ratios permit credit expansion of the present size and even of a much greater size, even if you would lose, say, half of the present gold reserves.

Exhibit 63 was also prepared by me. It gives the figures out of which the chart on Exhibit 62 has been constructed.

Member bank reserve balances, of course, are not available prior to the reserve system. The exhibit covers a period from 1879 through the spring of 1939. The sources of the figures are stated in the footnotes numbered 1 to 18 on pages 2 and 3 of the exhibit.

Questions by the Examiner.

As to what occurred between 1915 and 1920, that
291 caused the money in circulation to show a different rate of increase, having in mind the gold stock curve of that same period, I will state that the money in circulation alone does not move parallel to the volume of gold in the country, as you notice at almost any time. Money in circulation depends on a number of other factors, too. The parallel movement is between the gold stock and the deposit volume, rather than between the gold stock and money in circulation.

Money in circulation consists of cash, essentially small change and bank notes, different kinds of notes in circulation in this country. The volume of those notes in circulation is determined by such factors as, for example, the silver purchasing policy of the government since 1933. It depends on the habits of the country in having smaller or larger amounts of cash in their pocketbooks, habits which undergo changes in time, and which are independent of the gold stock. Therefore, that curve is not responsive to the gold volume to any major extent. What matters is the deposit volume and its response to the gold volume.

Incidentally, the deposit volume amounts to some fifty billion at present, the net deposit volume, without the eight billion of interbank balances, eight or nine billions, while the money in circulation at the present is no more than seven billions. In other words, money in circulation is only a fraction of the total amount of cash purchasing power in the country. It is a minor item compared with the deposits as related to the question of the effect on the price level.

There are several factors which account for that deviation. For that deviation in those years or that period during the war, it had to do with the hoarding policies, the cash hoarding policies of that period. During the war, European nations turned to dollar notes, because European moneys started to depreciate, and dollar notes for the first time became a favorite instrument of private hoarding, and we exported a lot of dollar notes from this country into

Europe and also to the Far East. That probably explains the most of this deviation at that time.

Later the explanation is, for example, in the years immediately after the depression, or rather during the depression, hoarding in the country, dishoarding after the depression, and the silver purchasing policy of the government.

Cross-Examination Interposed by Mr. Slaff.

On page 2 of Exhibit 63 I show a figure for gold stock in millions of dollars in the first column, and then I show another figure in millions of dollars which is different from the first column on the second page. That is for the period 1914-1933. Footnote (5) refers to the $287,000,000, which is the difference between the two gold stock items. The $287,000,000 has been subtracted in the reports which are published by the Federal Reserve system in its monthly bulletin, a technical publication, which I simply follow. I don't remember now what was the reason for subtracting in those years the $287,000,000. I think it had something to do with some accounting technique for hoarded gold.
292 They may have changed their technique of accounting for gold in circulation for that twenty year period. That is something which they at some time regarded as American gold in circulation, and afterwards they decided it was not regarded as part of the American circulation, or some such technicality in statistical tabulation. For the purpose of my tabulation I took the total figures, but recorded the figures also of the Federal Reserve Board publications. That applies also to the two parallel columns of figures for money in circulation for the years 1914 to 1933.

On cross-examination I will be prepared to supplement that explanation. The curves were constructed by me from the underlying figures. I shall make an investigation as to the reason for the correction in the Federal Reserve Board figures. At the same time I will remark that I made the correction on those curves, on the gold reserve stock and the money in circulation, so the relation is not changed throughout the item.

(EXHIBITS 62 and 63 for identification, offered and received in evidence without objection.)

Direct Examination by Mr. Morgan (Resumed).

Down to this time I have for the most part been talking about the normal relation between gold deposits and gold stocks for monetary purposes, and deposits and circulation. You inquire whether or not the normal tendencies have been felt in their effect upon prices since the beginning of the present depression.

Prices reached their bottom in general about in 1932, the end of 1932. Since that time recovery of the prices of the so-called raw or crude materials has taken place, reaching in early 1937 a rise of about 60%, just about as much as the devaluation amounted to. Since then prices have fallen, and even now the same wholesale prices, from most indices, indicate a level somewhere around 30% above the depression low, on the average. In other words, even the level of internationally marketed raw materials, their wholesale price level, is not adjusted even to the amount of the devaluation, to say nothing about the rise of gold reserves and other elements in the situation.

You inquire why price has not responded to the increased supply or annual addition of monetary gold and the corresponding increase in deposits resulting from that increase in the monetary gold supply. It is not possible to answer that intricate question in one sentence. In the first place, the price level does not necessarily adjust itself quickly to changes in the volume of gold. The history of the price trend with reference to the rise and fall of the annual output of gold in the past is that it always lags substantially, depending also on the business cycle. If you inject into the economic system a lot of new gold at the time of a boom or upturn, you get a very quick response in the form of more boom and higher prices. If you do it at a time of depreession or a crisis, then it has no effect at all, or it takes some time before it takes effect.

Take, for example, the latest comparable period, which is extremely interesting, the period of the discovery and development of the greatest gold reserves ever discovered and developed, namely, those in the Transvaal. In 1890 the Transvaal was discovered as a gold producing country. From 1890 to 1898 the world's gold production more than doubled, and, accordingly, the monetary reserves of
293 gold have risen very substantially. During this same period, especially from 1892 on, a very severe crisis took pace. From 1892 through the year 1896 prices had

fallen. In 1896, the end of 1896-1897, we turned the corner, so to speak, and the politically minded Americans ascribed this to the election of McKinley, which may or may not have had some influence. The real influence, or one real influence, was certainly Transvaal gold, probably more important than McKinley. At any rate, even after McKinley's election it took another year before prices started to rise.

From 1897 on, with several interruptions, such as during the Boer War of 1900 to 1902, during the crisis of 1907, etc., prices rose, up to the beginning of the World War, by about 50%.

Summing up, from 1890 to 1914, in those twenty-four years, the annual world output of gold has quadrupled—has risen fourfold. Prices had fallen up to 1897 and rose in the second part of that period, from 1897 to 1914, by nearly 50%.

You see by that example the lag of prices behind gold production, even under circumstances of much less interference by government and similar factors, much less of war problems, etc., existing then than exist at present.

In discussing the fluctuation in price levels, I meant the wholesale price level of raw materials or crude materials, which are virtually moving all over the world identically, except in countries with special monetary conditions, but all over the world, in the gold standard countries, they moved in the same fashion; so it makes no difference for that discussion whether I referred to the English or the American or the French prices.

As to the other factors which have tended to retard the normal and logical advances in prices that should have accompanied the tremendous increase in the annual increment of gold for monetary purposes and the consequent increase in bank deposits, and whether there are other factors than those I have mentioned, namely, the lack of confidence on the part of the banks and those who would normally borrow money for business purposes, which has caused them to lend and borrow a minimum, and the war conditions, and the other factors immediately entering into it, I will say that confidence is a general term; so is lack of confidence. It includes everything. Therefore, the question is how many things we include in that term and what are the factors which determine the existence or the lack of existence of the higher confidence or lower degree of confidence, which, incidentally, is a very weak term.

As a matter of fact, what happens in modern society is

that certain circumstances, such as technological progress, growth of population, expansion of the gold base and consequent credit expansion, stimulate the enterprising imagination because they create the expectation of profit. That profit expectation creates what we call speculation, and speculative investment and speculative buying. In the first place, speculative investment means that capital values rise.

294 Securities and real estate rise in price, because the future profits are discounted in advance in the higher present value or the higher present capitalized value of those future expected profits.

Furthermore, more inventories are piled up in expectation of the need for those inventories. That raises the price of commodities. The demand for commodities is further enhanced by the speculator who expects more inventory buying and, therefore, either keeps back his own inventories or adds to the fire by buying in expectation of other people's future purchases. These speculative psychological developments are the ones which bring rising prices under way.

A tremendous expansion of gold production and credit expansion, unless counteracted by war fear or depression psychology, necessarily creates such expectations. If they do not work out, it is then because other factors offset them. What are the other factors that upset these expectations of profit and the natural reaction of the speculative-minded entrepreneur? Well, there is the problem of costs, labor costs, the possibility or the expectation that higher profits will not materialize because wages might rise as much or more than gross profits. Another expectation of a negative kind is or may be the fear of higher taxes or the fear that exists that taxes may interfere with the profits; or a further expectation that international policies or national monetary policies may interfere with profit making. In other words, there are a number of expectations which, under given circumstances, offset the profit expectations naturally created by the expansion of the credit base and the credit system or the deposit volume.

That is the situation at present, and the question from the point of view of the problem we are dealing with is whether these negative expectations are likely to last. The positive expectation of monetary expansion is practically certain to last. The negative expectation may or may not last.

I am asked to assume that Europe and the rest of the

world got over the war scare and resigned themselves to peace, or attained to it, and state what ought to be the reaction on prices of the economic situation as it is presented here in my testimony concerning gold reserves and deposits, circulation, etc. I would like to formulate my answer a little more general than the question was asked.

If it comes to a major war, prices would rise almost instantly because war creates a scarcity, or rather, the expectation of scarcity. War is the greatest consumer one can possibly think of. At the same time war interferes with production as well. If you consume much more than usual and produce much less than usual, you are bound to have rising prices. Therefore, war always creates rising prices. That most certainly occurred in connection with the World War. The tremendous rise in prices during the World War was the outcome of the war situation. It had nothing to do with gold production. Gold production, as a matter of fact, went down during the war.

If, on the other hand, a settlement of the European 295 issues can be arrived at, and the Far Eastern issues, and the danger of a major war is practically eliminated, then the consequence would be (a) an elimination of a factor which inhibits capitalists from investing money, and money investing means demands for goods and for labor, and means that it has a price-rising tendency; and (b) it would also mean restoration of normal or more than presently normal channels of capital movement and the international exchange of goods and services, which in turn would also mean greater demand for goods. In short, the result would be again, even more than previously stated in connection with a possible general war, an upward tendency of prices.

The only case in which the international situation interferes with rising prices, and in which it depresses the general price level of the world, is the case which exists at the present time, namely, a case in which there is no war and no war scarcity of commodities, and there is no peace, and no peacetime normal exchange of goods, no peacetime normal possibility of investment.

That is a thing which, from the viewpoint of an economist, is very unlikely to obtain for long. As a matter of fact, both parties to the game, if it may be reduced to a basis of two, are far progressing in the direction of an economic breakdown, and therefore they are not likely to carry on without either going actually into war or actually making peace.

Cross-Examination Interposed by Mr. Slaff.

By both parties, I mean, of course, the two major groups of powers—the so-called Facist and the so-called democratic powers. I am speaking of the old world. Of course, I must be somewhat indefinite, because it is possible that Japan may step out and maybe Russia will step out; but in the main the problems of war are so interconnected on the two sides of the old world that if there is peace on one side of it, there is likely to be peace on the other; and the same holds true for war as well. I am speaking of a grouping on the one hand of Germany, Italy, Japan and their satellites, and on the other hand of England, France, possibly Russia, and their satellites.

Direct Examination Resumed by Mr. Morgan.

(Document entitled "Wholesale Prices and Index of Gold Production, 1790-1937," marked Exhibit 64 for identification.)

Exhibit 64 was prepared by me. The figures are all easily and generally available. The chart is intended to show the development of prices on the one hand and of gold production on the other hand. The price indices are taken from the English so-called Sauerbeck index and the American Bureau of Labor Statistics index, both wholesale price indices.

The most generally used data on the annual gold production are those of the Director of the Mint of the United States, which I use. They are regarded as the most reliable figures, and I merely translated them into an in-
296 dex number by using the decade from 1851 to 1860 as 100. The figures along the bottom of that exhibit represent the years covering the period from 1790 to 1938. The figures along the lefthand side are the indices in terms of 100—that is, in multiples of fractions of 100, showing in percentage terms the rise or decline of the price level and the gold production respectively. They are relative figures.

I will now explain that exhibit and what it discloses. The comparison between gold production and international indices—I call them international because they refer to internationally marketable articles, especially the Sauerbeck index, and largely also the Bureau of Labor index—is not very valid for the period before 1870, because before 1870 or 1873 very substantial parts of the world were still on the silver standard, or a combined gold and silver standard,

and consequently the comparison is vitiated through the volume of silver, silver production, and similar figures. The discussion, therefore, is not very fruitful for those periods.

If you look at the figures from 1873 on, practically the whole of Europe turned to the gold standard. England was already on the gold standard then; so was the United States, except for the period of the Civil War and the subsequent period of greenbacks. You will see that the index of gold production shows a decline which reaches the bottom in the early 1880's. The decline of gold production follows after a period of substantially rising prices in the previous two decades. You must go back two decades that the prices have risen, in the period from the end of the 1840's to the beginning of the 1870's, which rise was very substantial, and following which gold production has declined. The decline of gold production goes hand in hand with a very substantial decline of prices. Then the prices declined and reached the bottom in 1896 or 1897. The gold production already turned the corner in the late 1880's, and especially from 1890, with production in Transvaal, begins to rise rapidly.

The tremendous rise of the gold production, a fourfold rise, virtually, is followed a few years later by a gradual rise of the world market prices.

In 1914 the war started. Two things happened. One is that prices jumped up without any relation to the amount of gold production. That is the war scarcity situation. Gold production declined because of the high cost of the production of gold, which makes it unprofitable to produce gold except in the very rich mines, very high-grade ores. The bottom of the decline in production of gold was reached in 1921. That is at the same time when the price situation changes.

The prices have risen in spite of falling gold production. Then the price situation changes very substantially after the war. Prices decline and gold production starts to rise. Gold production rises slightly during the twenties, and in the thirties rises so that we have no place on the chart to express it. The words "To Infinity" express that there is no place on the chart for it. It would go up to over 297 600. In other words, we would have to add about the same size paper to express the rise in gold production.

The apparently unusual thing that happened in this decade is that in spite of this rise in gold production prices continue to fall. They fall in the long run. All prices have been falling, and they go on falling in spite of the tremend-

ous rise of gold. That appears unusual except that we have that in the long run period as characteristic of the relationship between gold and prices. That relationship is only a long run situation because so many factors enter into that situation that the two do not adjust themselves except in such long periods as one or two decades or longer. But, even so, even in terms of historical experience, this is an unusually long period of rising gold production being paralleled by falling prices. I account for that by all the factors mentioned before.

Cross-Examination Interposed by Mr. Slaff.

The Sauerbeck index is one commonly used and therefore I did not note down the base year. I think it is about 1870. It is quoted in the London Statist every week. It has been so commonly used for sixty or seventy years I did not refer to or put down the base here. I will supplement that figure.

As to why I did not cast these on to an equivalent index—in other words, use the same period for all three lines as 100 so that the lines would follow more comparably—I will say that I took them as they exist. They are the most popular indices, the most popular American price index and the most popular English price index. The gold production index I took has as the base years the first decade for which I took these figures. I don't think it makes much difference, however, in the long run. I think other statisticians would agree on that—that the benefit of the chart would not be influenced to any major extent by the difference in the base year. It would be an easy thing to recast them to 100, using any year as 100. You would get the same type of relationship between the curves.

The Bureau of Labor Statistics is from the Bureau of Labor in Washington. It is a wholesale commodity price index of the Bureau of Labor. It is called Bureau of Labor Statistics. I assume it is a statistical bureau, a statistical department of the Bureau. They have computed different indices. They have a short run index, for short periods, which is a monthly index. This is a yearly index which goes back a long period, and which is based on the decade of the nineties. I do not think the long range index base is 1926 as 100. I may be wrong on that, but I don't think so. I did not construct this index number, I just took it.

Direct Examination by Mr. Morgan (Resumed).

The legend "Bureau of Labor Statistics Index (1891-1900 equals 100)" means that the average of those ten years
298 is taken as the base, as equalling 100, and the price fluctuations of each year before or after that period is expressed in percentage of that 100. That is the explanation of the next similar notation under the "Value of Gold Production Index." The relationship remains the same no matter what base is used, provided it has the same figures.

Questions by the Examiner.

The Sauerbeck index is one constructed in England by a man named Sauerbeck. I think it began in 1860 to 1870. It is an unweighted wholesale commodity price index, and is not adjusted for any particular effect. It is a very simple index. They did not discontinue it between 1912 and .....; but I discontinued it on the chart for the reason that it jumped so high due to unusual inflation in England that it jumped up through the roof. There was an inflationary price situation in England. England was off the gold standard and prices went up for everything.

As to how the value of gold production was determined by this index, I point out that gold production is simply taking the amount of gold produced, translated into dollars, up to 1934 at the old price, and from 1934 on at the new price. It has been corrected to show the devaluation. It is not in ounces; it is in dollars.

(EXHIBIT 64 for identification, offered and received in evidence without objection.)

Direct Examination by Mr. Morgan (Resumed).

I have said that wages enter into the price level. The wage problem comes in in a two-fold way in the problem of the study of general price levels and their future possible development. One is the question of political influences, including bargaining organization of the labor market, and their effects on the wage level, or rather, on the labor situation in general.

In that connection my point was that labor problems, which are more than wage problems—they are problems also of labor efficiency in general and similar issues—are at present one of the problems pertaining to future profit

expectations of the entrepreneur, and one of the reasons why the velocity of circulation of deposits is as slow as it is, very much below what it used to be. That is one aspect of the wage problem.

The other aspect of the wage problem comes up in a different connection. Discussing and analyzing price trends, one comes to the question of how far volume of production and its expansion, plus technological progress, would affect the price level, and how far expanded volume of production and growing technological progress could and would offset rising prices.

In other words, suppose that inhibitions would be eliminated and that the rising gold volume and credit volume should work themselves out in the form of greater expectations of profits, thereby stimulating speculation, and carry into rising prices. Could such rising price trend be offset either by more production, that is, better utilization
299 of the existing plant and expanding plant on the one hand, and by technological progress, permitting more production.

I am asked whether I have taken into consideration the thought that by improved machinery man-power is dispensed with and production incidentally increased, and that this tends to bring about unemployment of men and depreciation or fall in the prices of the commodity used as a result of these mechanical improvements, commonly referred to as technological improvements.

Of course, every analysis of price trends would be very superficial if it did not take into account such an important element. The theory just stated is very widespread and has very great influence in many respects. I am discussing it, of course, in terms of a longer period, such as a ten or fifteen year period, and in terms of that longer period I would like to state very definitely my conviction that in such a period even substantial technological progress should not interfere and is not likely to interfere to any major extent with a rising price trend if such a rising price trend exists for whatever reason.

The reason for the ineffectiveness of technological progress in lowering prices is a very simple one. Technological progress creates in the first place new demands for labor and commodities, raw materials to produce the kinds of products which are used for the technological progress, and thereby stimulates prices upwards rather than downwards, at least for a while. In the second place, technological prog-

ress, inasmuch as it lowers prices of commodities which are already on the market, makes free a part of the consumer's income, which in turn is likely then to be used for purchasing something else.

Consequently there is the probability that in so far as technological progress lowers the price of commodity A, is contributes to raising the price of commodity B. As soon as a technological progress has taken place all over, in every kind of commodity within the same period, the probability is that the rising price trend in one corner offsets the falling price trend in the other corner.

And more important, technological progress does not profit the consumer very substantially in the form of lower prices. The profit to the consumer usually consists in getting some new commodity which he has not had before, or in getting a better quality of the same commodity rather than getting the same commodity at a lower price.

In the next place, the most important single factor is that the greater part of the advantage which technological progress makes does not go to consumer at all; it goes to labor. What happens in a period of technological progress in a long period is that real wages rise; that labor gets a higher share of the social product; that the consumer, other than labor itself, is not benefited in price terms directly from the technological progress to any major extent. Nominal
300 wages rise generally very substantially in periods of progress, in periods of inventions and improvements. This rise in nominal wages benefiting labor is independent of the lowering of the cost of living, and is certainly concomitant with a rising price level.

In several important points labor gains mostly from technological progress. I have some figures at hand over a long period, showing in periods of great technological progress wages have risen in extraordinary fashion. For example, take the long run period between 1890 and 1926, the average working hours in the United States were reduced from 58.4 hours per week to 49.8 hours per week, while hourly earnings from 21 cents to 71 cents—a decline of 20% or so in the working hours and a rise of more than 300% in the hourly earnings.

That represents a rise in nominal wages, not in real wage figures. And the same thing has happened in both England and the United States, showing also in the long run gains to the laboring class.

What I am driving at is from the point of the price level

the nominal wage rise offsets the decrease in other costs of production. For labor all over the country, including the kind of labor which did not have any major advantage from technological progress in that very long period of 36 years, the gain is so substantial that it couldn't be offset by a similar rise in the average productivity of the wage earner. It is not likely that the average American wage earner will produce substantially more than three times, or almost four times, the value product that he did 36 years ago.

The figures are for the manufacturing working hours and wages, and were compiled by Professor Paul Douglas in his study of wages. I did not compile the figures. I took them from him because he is regarded as a high authority. I am not sure whether I have comparable figures for 1937 and 1938. There are some figures available at the Bureau of Labor Statistics, but how comparable they are to these long run figures I can't state now.

There is a draftsman's error on Exhibit 62, which is the graph of member bank reserves and related items, in that after the year 1928, the figure "28" is repeated. After the year 1928 it should be 1929, 1930, etc. The error would make no change in the chart. It would not be necessary to change the graph in any way. The chart is correct but the numbering of the years is wrong.

I made the observation that the advances brought about by inventions, improvements, etc., do not operate to reduce wages. I explain that in this way: The main reason for rising wages in a period of technological progress is that progress creates a new demand for labor and for labor of higher skill. More labor is demanded, and labor of higher qualifications, thereby, for both reasons, raising the average price of labor.

301 When technological progress is taken place you can see, at least in the very early stages, that it does not mean to displace men or machines simply, but it means to displace less qualified men by more qualified men. We have to put in more intelligent men, technically more skilled men to do the work, even if we have to put in a less number of men. The consequence of the progress is that the volume of production increases so much that a new kind of production arises, namely, the production of new kinds of products. That in total has a double effect, more demand for labor and demand for more skilled labor.

Counsel has referred to the history of the automobile. I am not very familiar with the technical and engineering

principles involved in that industry; but I would like to state that technological progress did not displace a product but added a product to the old one. We do not travel less on the railroads than we did before. As a matter of fact, the volume of traffic on the railroads is larger now than it was in 1920, but we added a new volume in the way of movement on the highways; and we thereby added a tremendous new volume of additional demand for labor. Another example of the automobile is the fact, in recent years especially, that technological progress does not necessarily benefit the consumer in the lower price, but rather in the form of higher quality.

The automobile created a demand for good roads, and it created a demand for materials to be used in constructing the good roads, for the technical services of those used in the planning and building of these roads, and for labor employed in the building of those roads. You might add the increased production and use of rubber, which was very slight before the automobile and which has become a great industry since the automobile came into existence. Also, in connection with the rubber, carbon black became widely used and became a very important commercial industry because of its use with rubber in the manufacture of automobile tires. The automobile has also had something to do with the expansion of the oil business. Prior to the automobile they used crude oil originally as a method of creating artificial light and then gradually for power; but the total volume of it used for those purposes was very slight. With the oncoming of the automobile and the use of gasoline as a motive force, it immediately resulted in a tremendous expansion of the oil business, and that great industry is founded largely upon the demand for gasoline created through this invention known as the automobile. A lot of people were provided work to furnish services to that industry; and as a result of that invention it did not follow, as a lot of people thought it would at that time, that a lot of people were put out of work on the railroads. That exemplifies very well the effects of technological progress.

I would like to say one more word about technological progress. I have here a chart and a table for Great Britain from 1850 to 1910, which was a 60 year period before the war, taken out of the book of Walter Layton, former editor of the London Economist, called "An Introduction to a Study of Prices," in which he presents three sets of figures:

average money wages, real wages, and average retail
302 prices. which are more realistic than wholesale prices.
The real wages have been constructed out of retail prices with allowances for unemployment.

This is the picture he gets for the 60 year period from 1850: that prices moved twice upwards 25% above, then downward some 20% below the normal line, and came back almost exactly where they were 60 years before—that is, retail prices in Breat Britain; and if we take 100 as the average retail price in Great Britain in 1880, 98 is the average retail price in Great Britain in 1910. Within this same period nominal wages, money wages, moved up from 100 to 179½; in other words, almost double in the same period, while prices remained virtually in the long run the same. Real wages moved closely parallel to money wages, except that they are slightly below money wages, mainly because of the correction for unemployment.

I have said that retail prices were more realistic than wholesale prices. I meant that in connection with changes in wages, to show changes in real wages, and only for that purpose.

(Document entitled "Money Wage, Real Wage and Price Trends in Great Britain," marked Exhibit 65 for identification.)

Exhibit 65 was prepared by Mr. Layton. I have just made photostatic copies of the pages. The underlying data would be available in his book. It is "An Introduction to the Study of Prices," London, 1920, by W. T. Layton, and that book will be in every library.

Rising prices of commodities tend to stimulate production. The price can be looked on as a ratio between demand and supply, and the higher the demand, the higher the price; and the greater the supply, the lower the price. Therefore, one might conclude that that tendency toward increased production has a slightly offsetting effect on rising prices.

Assuming that the tendency to increase production will exist during the next ten or fifteen years. I am asked whether in my opinion the tendency will be of sufficient volume to offset the tendency of prices to rise. Theoretically, that is, merely calculating on paper without regard to human psychology, increase in production can go some way to offset rising prices; but even theoretically it cannot go a very long way, because, suppose prices started to rise at a time when the capacities, the productive capac-

ities, are used only to a minor extent, say, 60% or 50% or less of the productive capacities are used, then under those circumstances price increases will meet an obstacle.

When expanded production at given wages begins to take place, there will be a falling cost, because the overhead per unit of output declines with the growth of that increase of production. The more you expand production from a low level, the less overhead at given wages and other prices pertains to a unit of your output, and therefore the cheaper you can sell, theoretically at least, your product.

But even in this theoretical consideration one must take into account that if the rise of prices continues, then very soon the limit is reached, because of the limit to dimin-
303 ishing costs, and the plant comes under the law of rising costs. From a certain level of using this capacity the overhead costs, instead of diminishing, rise; and when it reaches 100%, then a further rise in the volume of production is only possible when you expand the plant, which means a duplication of plant and that the whole overhead must be duplicated more or less, and then there is no more fall in overhead. As a matter of fact, since the new plant is not used 100% of its capacity, there is a higher unit overhead than there was before.

In other words, even theoretical expansion of production under the most favorable conditions leads after a while into a situation of rising cost or diminishing returns per unit of output, and therefore to a burden on production by adding to costs rather than diminishing them, except for that short period of initial increase in production.

As I say, this is a theoretical point of view. The practical point of view makes even the temporary advantage doubtful for the following reason: In a period of rising prices the psychology is likely to turn speculative in the direction of assuming further rising prices. There is no more fundamental law in the business cycle than that when prices rise people assume a further rise, and when prices fall they assume a further fall of prices. They are always going with the wave up to a certain point, which is usually too late, as experience points out.

The consequence is that with every rise of prices they do not give consideration to the possibility of diminishing returns, when they will operate or when they will not operate, but the psychological speculative element in the market is far more important than are the material factors in the plant, and speculation carries prices, when once prices

start to rise, in spite of the theoretical probability or possibility that they should not be carried to that extent at that time.

I wish to add one more remark to the discussion of technological progress and its effect on prices. I refer to the figures published by Profesor Douglas in his studies of real wages. His figures also definitely indicate that for long periods, such as from 1879 to 1925, the so-called relative real earnings per worker rise parallel, exactly parallel, to what is called the relative productivity per worker. In other words, the more valuable the product that is put out per worker, the more the real wage per worker rises over longer periods. As a matter of fact, the longer the period the stronger the tendency to have more rise in the wages of workers than in their productivity. I am speaking percentage-wise, and therefore I call it relative.

My last observations were intended to support my thesis, namely, that labor tends to get a greater share in the social product with rising productivity, which is in other words, greater technological progress. The question was asked why labor gets a higher share in the social product in
304 a longer period of technological progress, and I tried to answer the question; but I did not mention another element of the situation, namely, the fact that labor tends to unionize itself, or organize itself, under modern conditions and to make the best out of its marketing possibilities, more so than it did in previous periods, which, of course, further strengthens its position.

(Document entitled "Wholesale Price Index, United States Bureau of Labor Statistics, 1926—100," marked Exhibit 66 for identification.)

Exhibit 66 was prepared by me. The chart was drawn from the figures of the Bureau of Labor. The purpose of that exhibit is merely to indicate that different sections of the price level move up and down in a fairly corresponding fashion.

As to the four lines across the chart, one is the general price level for all commodities, meaning wholesale prices, and the others are raw materials, including agricultural products, semi-manufactured, and finished products, respectively. All the commodities which the Bureau of Labor covered are included. These data are published in the monthly report of the Bureau of Labor and reprinted in the Department of Commerce monthly publication.

Cross-Examination Interposed by Mr. Slaff.

The scale is entirely different on the wholesale commodity price index of the United States Bureau of Labor Statistics in Exhibit No. 64, and on the index I used in Exhibit No. 66, and consequently, on Exhibit 64 it is compressed in a fashion for the price change to appear much steeper than on Exhibit 66. On Exhibit 64 the Bureau of Labor statistical index for 1926 is approximately 190, and for the year 1937 it is approximately 90, so if I use 1926 as 100 on Exhibit 64, the index for 1937 would be less than 50. On Exhibit 66, which uses 1926 as 100, the all commodities index is 75. I would not say whether the Bureau of Labor statistical index on Exhibit 64 is not the all commodities index on Exhibit 66 without looking into it. At first sight it would indicate it, but I would like to check on it more precisely and see what index it was. It may be that the Bureau of Labor statistical index is more comparable to the Sauerbeck index. It may be the index of the raw material group, material prices, rather than all commodity prices. I will check it.

(Exhibit 66 for identification, offered and received in evidence without objection.)

Direct Examination by Mr. Morgan Resumed.

Coming back to Exhibit 64, it shows that 100, so far as the Bureau of Labor Statistical index was concerned, was 1891 to 1900, on the average.

(Document entitled "Wages and the Price Level, 1913-1938," marked Exhibit 67 for identification.)

Exhibit 67 was prepared by me. The information set forth there was obtained from different sources. The exhibit is based partly on the so-called Snyder index of general price levels, which was prepared by Carl Snyder, previously chief statistician of the New York Federal Reserve Bank, and has been then continued from 1937 on, when Snyder discontinued it, with figures of the Bureau of Labor Statistics. That is a general price level index on the chart. Then in part it is an index of prices for commodities used by Natural Gas Pipeline Company of America. Those prices, as well as the index, have been computed by me. It is a tentative index. The real weekly wage and public
305 utility wage are published by the Bureau of Labor and the National Industrial Conference Board, respectively.

The lines designated as "Company's Wages" were compiled by me out of data which the Natural Gas Pipeline Company provided.

The purpose of this chart is to indicate that the long run fluctuations in prices of commodities used by the company and the wages paid by the company, respectively, and by similar companies, public utilities, are fairly in accordance with the comparable general price changes, and the real weekly wage changes.

As to the effect which the tendencies which I have testified to will have upon the operations of Natural Gas Pipeline Company of America and Texoma Natural Gas Company during the next ten or fifteen years, I would like rather to discuss the past or the present than the future in that connection. I know more about the past and the present than the future.

It appears from the data I possess and which I have collected and will present in a moment that the company uses both for operation and for construction a great many materials. It uses a range of materials which covers dozens of groups of articles, from paper containers to iron and pipes and construction material, oil and chemicals, and all sorts of materials. In other words, its raw materials budget is not restricted to any major extent to any small number of outstanding articles. It is very varied and a large number of articles enter into it. The consequence should be that if you build up an index of prices, as is tried tentatively on this chart, made out of prices of articles which will enter into the operation and construction of the property of the companies, then that index ought to be more or less similar to the general price index, since it contains a great number of articles which are also in the general price index, and since, as a previous chart of the Bureau of Labor Statistics indicates, the different major groups of articles move fairly parallel in their prices in the longer run, such as in a number of years. If you glance at this chart, Exhibit 67, you will find that up to 1930 the index of prices for commodities used by Natural Gas Pipeline Company of America has a greater amplitude of swings than the Snyder index has, which is the most general price index we possess, but that the direction of the swings and the timing of them fairly coincide with the general price legel index.

As to wages, it is more difficult to find comparable data. I have chosen on the one hand the public utility wages of, the Industrial Conference Board, and, on the other hand,

the real weekly wages of the Labor Bureau. The two are not precisely comparable, I admit, but it is interesting to note that there also exists a fair degree of parallelism. For the period of the history of the company, for which I do not have the complete figures for every year, but I had the figures both on wages and on prices of commodities entering into the cost of operation of the company for the beginning of the years and the ending of the years of the period 1931 to 1938, there again you find not a very
306 precise parallelism, but some amount of parallelism.

Of course, that period is not very long. The general conclusion from these charts, especially the comparison of the index of the prices of commodities used by the company with the general price level index, is that at least so far as price levels are concerned, there is a very great amount of correlation, which is theoretically and a priori most likely to be the case. If you pick out fifty articles, and fifty articles of different types, from chemicals to iron pipes and other metals, and paper containers, and put them together into an index, you will get over a longer period an index which will move very similarly to a general index of prices, and it would be a great surprise if it should not so move, because it is representative of the general price index, consisting of very different prices.

The only reason why deviations would occur is that the general price index consists only of wholesale prices, and an index such as is used for the prices of commodities applied by the company in its operations consists partly of wholesale prices and partly of retail prices; which have somewhat different behaviors over periods of years. Retail prices are more sluggish, do not move so fast, are more sticky, stay longer on a level, and sometimes even for as much as a year or two move contrary to the wholesale price tendency.

Questions by the Examiner.

I am not sure that that would expalin the movements between the years 1933 and 1937, but it may. I did not make sufficient study of the situation of the individual prices as to why they happened to move as they did to answer the question wholly; but that could explain it.

Cross-Examination Interposed by Mr. Slaff.

The broken line in the company's price index indicates I haven't had complete figures and I disconnected the two points of the line. Therefore, that is not very indicative as to whether the price movement was similar or was not similar to the general price index, but the index previously to 1930 generally seems to indicate a general correlation in the tendency of price movement.

As to whether the movement in the index of prices for commodities used by Natural Gas Pipeline Company of America between about the middle of 1934 and the beginning of 1938 could not have been the same even generally as the movement of the general price level using the Snyder index, I do not see any reason why it could not have been generally the same.

Counsel inquires if there would not be a reason, due to the fact that at the beginning of the year 1938, the Snyder index is some 36 or 37 points above the same index in 1934, whereas the index prices for commodities used by the Natural Gas Pipeline Company of America are approximately 307 the same at the beginning of 1938 as at the middle of 1934. I will state that the Snyder index is a very curious index, and that is why I chose it. It includes everything, even security prices. It is, as I mentioned, the most comprehensive index we have in America. That period was one in which security prices went up very substantially, much more so than most commodity prices went up in this country, and that is partly the explanation for the difference. I was using that index as one of general price levels. The index for commodities used by Natural Gas Pipeline Company of America moved the same direction, upward, over the same period that the Snyder index did. There was a very substantial discrepancy; but they would be different if one moved upward and the other downward. We may not agree on the terms we use.

Questions by the Examiner.

There is a gap in the solid lines between the years 1930 and 1932 because I do not have the beginning figures or the early figures. They are not available in sufficient completeness.

As to the commodities prices used by the company, the

breaks come simply due to the fact that I did not compute for that period as I did not have the complete figures, just as for the periods afterwards. I had partial figures but not complete ones.

The index figure was not given to me by the Company. They computed the figures and I computed the index. It is a weighted index. The salaries of the higher employees are not included. It includes only skilled and unskilled workers. There was a period of construction during which I did not get sufficiently comparative figures to construct an index number comparable with the following period. Therefore, I left it open, and I think it is a very good point that the two would not be even quite comparable, the two periods, because the wages meant something different in the one period than in the other period.

As to how, when I tack on to the Snyder index curve the index curve for the Bureau of Labor Statistics, I know those two curves mean the same thing, I will say, that they do not mean exactly the same thing, but are for the purpose of indicating the general price trend in this connection. The purpose of a chart like this is not to prove in percentage terms how two things correlate with each other, but just to demonstrate to the eye whether there is some general tendency in the same direction, or whether there is no such general tendency at all, and the whole arrangement refers to the longer period rather than the few years. The fact that the Snyder index includes securities does not throw you off when you begin using the Bureau of Labor, except, of course, for a short period of one or two years.

Direct Examination by Mr. Morgan, (resumed).

308 I find that the comparable prices on the materials used by Natural Gas Pipeline Company of America have risen from 1931 to 1938, as indicated on this chart. It is a slight rise, but a visible one. I may add that while the company's wage index is a weighted index, I could not make a weighted index of the company's prices, because I could not get sufficient data as to the amounts of each commodity used in each production process.

Cross-Examination Interposed by Mr. Slaff.

I constructed the index by roughly grouping the commodities in seven major groups. After talking to the chief accountant of the company, we came to the result that those

seven groups represent fairly corresponding volumes of money expenditure, and by this correspondence and by grouping them in seven groups and taking the average of the seven groups, we take a chance on getting a somewhat weighted index that is a better one than an absolutely unweighted one.

The index or the change within each group from year to year was obtained by taking the figures of each commodity within each group and giving them equal rate. I used dollar figures, the price of the commodity expressed in dollars, and then computed an index number—took the average.

The company's wage index is a weighted index constructed from an index of skilled and unskilled labor, and the two together weighted according to the amount of dollars spent on each.

I have work sheets, but they are not very readable. I can present them, but they are not in the stage in which they could be used. They would have to be rewritten, but I can show them to you.

(June 27, 1939.)

Direct Examination Resumed by Mr. Morgan.

I would like to make a statement concerning the gold coming out of industrial uses, as I have the 1937 figure on that use. The statement applies to Exhibits 60 and 61. The gold flow into industrial use amounted in 1937, net, to $3,214,393 in terms of dollars at $35.00 per fine ounce. Consequently, this means less than one hundred thousand ounces of gold absorbed by the arts.

I also wish to make a supplemental statement regarding Exhibit 64. There was some question about it yesterday and I checked it. In the first place, the remark in the legend on Exhibit 64, "1891-1900 equals 100," applies also to the Sauerbeck index. They have both been brought to the same base.

In the second place, I checked to compare the Bureau of Labor index in that exhibit with the Bureau of Labor index on Exhibit 66. There was some question yesterday about a discrepancy in the two indices. I checked that, and there is no discrepancy. When I sought to admit there was a discrepancy, I looked on Exhibit 64 at the black line instead of looking at the dotted line, an error which one easily commits on a complicated chart, especially when the room is very warm.

309 Looking at it you will see that they are exactly the same in percentage terms. For example, the Bureau of Labor index on Exhibit 66 is, for 1928, 96.7, and for 1932, 64.8. The difference is 31.9, which is 33% difference between the two dates.

On Exhibit 66, with the base 1926, when you take the year 1926 as the base year and look at the chart, you will find that for 1928 for the general commodity index, the comprehensive index of all commodities, it is 96.7; and for 1932 we have 64.8. There the difference is 31.9, as shown here, which makes 33% decline in price.

If you will look at the same period, 1928 to 1932, on Exhibit 64, where the Bureau of Labor index is brought on another base year, namely, on the last decade of the previous century, then you get for 1928, 184, and for 1932, 123, which is a difference of 61, exactly 33%.

In other words, in percentage terms the two curves, both on different bases but both brought on the same figures of the same bureau, move in exactly the same fashion. At first glance at the chart, the chart being narrowly drawn as it is, the two lines being so close together, it is easily misleading, and I was misled myself yesterday. The reason, it seems to me, is that I looked at the heavily drawn line instead of looking at the dotted line.

Questions by the Examiner.

The theoretical basis for my series of observations just made is that I think 1926 and all the other dates on Exhibit 64 refer to a common base so that a common relationship between 1926 and all the others is observed. The same figures are used on both charts. If you take such index numbers for any period, you can shift the base as you please, and if you correctly compute it you will always get exactly the same percentage relationship.

Cross-Examination by Mr. Slaff Interposed.

The index figure for the year 1926 on Exhibit 64 for the Labor Bureau index is somewhere around 185, taking the year 1926 as 100 in order to bring it comparable with Exhibit 66. It is very narrowly drawn on that chart. Over that year's period, from the beginning of 1926 to the beginning of 1927, I have eleven or twelve dots; but

those dots do not represent monthly indices. They are just a dotted line.

At the beginning of the year 1926 the index begins at approximately 198. At the beginning of 1927 the index is at approximately 184. Therefore, the average index figure for the year is about 190. I wouldn't say for sure because there could be an error in drawing such a chart with dotted lines in such a narrow space, and it may be it was moved a little out because the other line was pressing over. I could not rely exactly on that; but it is approximately 185 or 190. 190 equals 100.

The index for 1937 on Exhibit 64 is about 88.
310 Translating that into the 1926 base, my index figure for last year would be about half. The price level on the all commodities index on Exhibit 66, where 1926 is used as 100, fell much less in percentage terms. Either the indices on Exhibits 64 and 66 are not the same, or else there is an error in the line on one of the two exhibits, or there is a possibility that we are both wrong again as we were yesterday. But, I would not rely on my own judgment when I look at the chart quickly, without computing them again. I should like to figure it out in an unhurried manner.

Direct Examination by Mr. Morgan Resumed.

Turning to Exhibit 67, my attention is called to a heavy black line beginning near the lefthand lower corner and extending upward rather steeply to a point near the top of the base, about at a point for the year 1920 which I have labeled "Index Price for Commodities Used by Natural Gas Pipeline Company of America." Then there is another line which I have labeled "General Price Levels, Snyder's Index." There is a sharp elevation of the solid line in the early twenties above the general price level. I think the reason for that is that the company used a great deal of materials which enter into the category of war materials, such as steel and steel products, pipes and similar articles, with the consequence that their prices went up more than the average price level did, and went down when the correction of the inflationary price situation appeared after 1921. It went down more again than the average prices went down. That

looks to me like a satisfactory explanation. There may be some additional reasons for particular articles included in the Pipeline Company's price index.

Questions by the Examiner.

I made an examination of the list of commodities used by Natural Gas Pipeline Company of America; but I haven't made since yesterday any further study which would go into the price history of each individual commodity or group of commodities which would explain why in the 1920's it went down more than the average price of all articles did.

I do know that a great many of the materials used by these companies are steel, such as pipe, casing, valves, machinery, and things of that sort, and also hardware, lubricating oil, and similar materials which have been particularly in demand during the war.

In 1920 steel was extremely high, higher than the average price level had risen, as were a number of war materials. That would explain for me at first sight the whole difference; but, as I say, there may be some more reasons in particular commodity situations which I did not follow.

Direct Examination Resumed by Mr. Morgan.

I have examined and analyzed the materials and classified the materials which are used by pipeline companies in my study, because I had to construct an index number for that. Before I go into that index I wish to make a further statement. After 1922 you will see that the 311 index number on Snyder's index fluctuates rather more than the company's index does, which indicates that the great swing immediately after the war in the prices of the commodities used by the company must have been due to particular reasons prevailing at that time.

I have worked out a memorandum about the way the index numbers of the cost behavior of the company have been constructed, both for labor and material. The material prices will be a composite index number for a period 1913 to 1930—that , previous to the company's operations. We took a simple arithmetical average of the indices of the following groups of articles as they are

published for those groups of articles by the Labor Bureau, assuming, of course, that the articles falling within that category used by the company are just about the average net category, which is an artificial assumption; but every index number consists of little artificialities. It is only an approximation, only approximately exact. Steel pipe, hardware, lubricating oil, kerosene, lumber, building materials, and chemicals. Then with these seven groups we took the simple arithmetical average, and this line will be shown by the heavily drawn curve on Exhibit 67.

It is rather difficult to weight these averages, the amount of expenditures, the company expense on each of these categories. The company provided us with yearly lists of expenses by departments for different categories of commodities, out of which I computed their yearly expenditure for each year for each category of articles, which was rather difficult because there are possibly some articles each time that are not exactly the same as another kind of article. It took some assumptions to bring things to one denominator. Then the annual expenses for each category fluctuates greatly from year to year. In one year they might spend much more on hardware, and in other years they might spend much more on steel pipe.

At this time the lifetime of the company is rather short. Anything I would make in terms of average of those years for the lifetime of the company may not be very good for the next five years or the next thirteen years, because their expenditures may change in those years, and the expenditures within the groups here are not or may not be strictly accurate as a guide. In other words, there will not be exactly the same expenditures each year by the company, but over a longer period the differences are not very great. I think it is scientifically permissible to regard this as a fair average.

I may mention in that connection that most simple computed index numbers, such as the Sauerbeck index and the Economist Index of wholesale prices are unweighted indices; but their methods over longer periods are just as reliable as your highly refined, specialized index numbers which represent the weighting of articles, and are just as representative for the seven categories

of articles from the point of view of the company's expenditures.

For the period after 1930 the history of that index 312 number is this: The company started construction in the course of the year 1930. We started computing index numbers from the middle of 1930 on the assumption that we will take in the figures of the Bureau of Labor and the actual prices paid by the company.

Afterwards it turned out that during the period 1930 and 1931 the company was not in operation but was only in construction. Therefore, I do not have and could not get anything like figures on their operative materials, and I left that period blank. We didn't compute any more on the old index, and we couldn't compute yet on the new index.

In the middle of 1931, or a little after the middle of 1931, when the company opened operations, we started out to figure out this new index number for its own material price. The way we proceeded there was to get first data on the kind of materials the company uses, in detail such as we already had for the previous index; then to see what prices the company has itself or can get from its suppliers, in so far as it is possible, and where the company has no figures, to use the Bureau of Labor figures for individual articles or groups of articles. By that method we were able to compute for a few years an index number which extends from the middle of 1931 until the middle of 1934, and again for the beginning of 1938.

In the intervening period we had partial figures, but not complete ones. Since the same figures were not available as for the few years before and for the half year after, we therefore decided not to use any figures for that period in computing any index number, and we changed from the figures of the company to the figures published by the Labor Bureau.

I can give a few more details about the way we computed the index numbers of the company's material prices. Chemicals and office furniture composites were simple averages of the company's indices which are taken from the Bureau of Labor Statistics wholesale price bulletins. The base was changed from 1926 to 1937, as for all company price indices, for this computation. For valves and fittings we received data furnished by the

company, price data. The quotations were averaged, unweighted, and put into an index number, by using again the 1937 base. The indices for hardware, chlorine, lubricating oil, were Bureau of Labor figures on a 1926 base transformed into a 1937 base.

The so-called composite is simply an arithmetical average of the component items as published by the Bureau of Labor. The price index is simply an unweighted aggregate of prices and quotations furnished by the company. The base again, as always, is 1937.

The composite total index which is represented by the curve, called on Exhibit 67 the company's material index, consists of the arithmetical average of the following indices: office supplies, pipe, valves and fittings, hardware, chlorine, lubricating oil, office furniture, kerosene, chemicals, lumber, building materials, red lead, storage batteries; and some of those groups consist in turn, as I mentioned, of arithmetical averages of a number of indices of component materials.

313 I don't pretend that this is a perfect picture of what happened, but it would take tremendous work, it could never possibly be done, to present an exact picture of the index number of a single firm's cost element in which there are a great number of materials of every kind which are not quoted anywhere, for which there are no indices published, and the company itself has so many data on its own purchases that it would take statistical work of several months to collect those data and organize them over a period of years andt bring them to denominators to permit the drawing of very exact index numbers. It is an approximation which has some indicative value.

Personally, I would rely more on the value of the index number for the previous period, previous to 1930, because it consists of simple data which are more comparable with the general price level index and because it covers a much longer period.

It is a very important aspect of the comparison that the data for the history of the company covers only a short period; but I still say my impression of this price study is that there is a fair correspondence in the general trend of prices of commodities used by the company and in the general trend of what is called the general price levels in the country. This is, of course, theoretically obvious.

If you spend money on these different types of com-

modities, ranging from office supplies to storage batteries, from red lead to lumber, pipe, fittings, building materials, you cover so many things, as I mentioned yesterday, that a priori it would be most astonishing if your index number of prices fluctuated or would be very different in trend from the general index number, and an explanation would be needed if major differences for any length of time would occur. That the trend is about the same, as a matter of fact, ought to be, a priori, more or less obvious.

As to the relation between the company's wage index and that of the real wage index set forth on Exhibit 67, I will say that the company's wage index means the index since the beginning of the company's history. Perhaps I should say something about the public utility wage index that I have on Exhibit 67. This public utility wage index is published by the National Industrial Conference Board. It is an index of hourly wages paid workers in gas manufacturing plants. It is not on the 1937 base.

This so-called public utility wage index, this N.I.C.B. index of gas workers' wages is brought up to 1930. I have the figures available until 1936. The reason I did not draw them on the same chart was the same as with the index of prices for commodities used by the company, namely, I intended to turn from 1930 on to the company's own wage index; and again the same problem arose—that it was a construction period—and we did not have proper comparable wages, so that there again we had to go to other figures. As a matter of fact, I have the figures with me now and can present them. That wage index moves very much, as to 1930, as the index of real weekly wages does on the same Exhibit 67.

314 From 1931 on we used the company's own wage index, for which I had the figures from the middle of 1931 until well into 1938. That index is a weighted, composite index of two indices, one for skilled labor used by the company and one for unskilled labor. Out of the two, by weighting in accordance with the actual expenditures in each category skilled and unskilled, I constructed this one index number which appears as the company's wage index.

Questions by the Examiner.

That is not the N.I.C.B. wage index. I know how it would compare with the company's index, and I could draw that in. Roughly, what is called the public utility wage

index, N.I.C.B., first goes a little down, then goes up from 1932 on much more substantially than the company's wage index does at the beginning. I used the N.I.C.B. index for the period from 1930 to 1936. I have the figures here and will read them in later.

It goes up more steeply than the company's wage index does; but the general tendency of both, except for the year 1932, is exactly the same. In 1932 there is a substantial fall, or some fall of 10% or so, in the wages which the company paid, and there is no similar fall in the general wage level of gas workers; but the tendency of the period as a whole is the same.

Direct Examination by Mr. Morgan Resumed.

The wage index of the company, as I stated, is composed from two indices being weighted for skilled and unskilled wages. The skilled wage index was worked out by grouping the employees of the company, classifying them according to the type of work done and the wage they got, based on information given by the company. The various groups were then in turn weighted, according to the rates of pay on January 1, 1937. The difference in wages among the skilled workers over the period of some six or seven years did not vary greatly, so it made no difference which date I took for weighting them.

It was weighted according to rates of pay received on January 1, 1937. In other words, I did not add up all the wages paid to skilled workers and divide by the number of skilled workers, which would be an unweighted average; but I classified them into groups according to the type of work they did, and according to the wage they got, and then weighted the groups according to the number of people in each of them on January 1, 1937, and got therefore a weighted index of skilled workers' wages, weighted according to the number employed at the corresponding rate of pay on January 1, 1937.

The final index for the skilled group was constructed by segregating the different groups for each year or half year brought to a 1937 base by dividing that by the aggregate for 1937.

The index for unskilled labor was constructed by the same method, except it was much simpler because it
315 did not have to be classified into groups. They all had practically the same wage rate. As I mentioned before,

the two indices were again weighted into one index. I weighted the skilled and the unskilled according to the amount of pay paid to each group on January 1, 1937.

The illustrative purpose of this chart is merely to demonstrate that there is a general tendency of correlation between general price levels and the company's price level as shown by the wage levels and the company's wage index. That is to say, there is a strong tendency of similar direction in major periods, which does not exclude short-term deviations. That should be obvious.

In the case of labor, the situation is that the workers used by the company are the kind of public utility workers who would be used by any company in the utility filed, at least in the gas utility field. They are not particularly specialized workers, with few exceptions, for this kind of work. Nor is this company the only one in the field, even in the natural gas field. Consequently, for any major period the wage rate paid by the company is determined by the market, as the company is only one purchaser in the labor market, only a minor element, especially now in times of collective bargaining, minimum wages, and unionization developments tending to spread all over; so it is very unlikely that for any major length of time the company would be able to make a different trend in the development of wages, to any substantial extent, from the general trend of wages, at least in its own field. The chart serves the purpose of roughly demonstrating that argumentation.

Direct Examination by Mr. Hedrick.

Referring to my Exhibit 67 and the line entitled "Public Utility Wages, N.I.C.B. Index," it will be noted that that line stops as of the first of July, 1930. I stated a moment ago that I had the figures which would extend that line over to January, 1936. I will now read them into the record by half years—that is, for January and July.

January, 1930, as the chart shows, 107.4. July, 1930, which is still on the chart, 105.7; that is, it should be. It is a little lower than it should be. Charts are never quite exact.

January, 1931,	110.5
July, 1931,	109
January, 1932,	110.7
July, 1932,	110.1
January, 1933,	111.2

July, 1933,	110.1
January, 1934,	118.2
July, 1934,	120.8
January, 1935,	121.7
July, 1935,	122.8
January, 1936,	123.5

The method of computation by the National Industrial Conference Board has been changed by adding a great
316 number of new companies, and the Conference Board warns the reader not to regard the new index as quite equal to the old index, so I take their warning and do not give the new figures.

Direct Examination by Mr. Morgan Resumed.

As a result of the analyses and studies I have made, I will give my judgment and opinion as to whether the costs of materials and labor of these two pipeline companies will be higher or lower or remain stationary over the next twelve or fifteen years.

My general conviction is that within a period as long as ten or thirteen years a major upward trend of prices as compared with the present is most likely to occur. The gold situation, the tendency toward credit expansion, the desire of mankind in the western world to take advantage of the expansion possibilities which the gold and credit system offer, the opportunities which a capitalistic system provides through rising population, technological progress, etc., together are most likely to lead into a major upturn in a period as long as that. Most likely is the only thing I can say, because, of course, nothing is ever absolutely certain in economic matters in the future; but all factors at play seem to indicate that such development would almost necessarily take place sooner or later, and ten years or more are certainly long enough, certainly in comparison with any other depression period of what we call modern capitalism, such as the last 160 years, in which we have never had a similarly long period of falling of prices without at least temporarily, such as for a number of years, returning to a substantial upward movement.

In addition, in the present situation, we have a number of what are usually referred to as artificial factors tending in the same direction. We not only have an enlarged credit base, and not only have credit machines in every country

—not only in this country—been geared to maximum potential expansions, but we also have governments doing their best to foster that expansion, and definite inflationary tendencies in a number of countries on the top of these potentialities of a more natural kind, inflationary tendencies which in most previous depressions were not at work, or not to any similar extent at work.

Taking all these elements into account and considering, as I tried to, the possibilities of interference or of inhibitions, such as by technological progress, which might reduce prices, such as expansion of production, which might offset rising prices, my conclusion would be that a period of ten to thirteen years would be more than ample to provide for the possibility and the great probability that those possible inhibitions would not work out and the factors tending to raise the price level would become effective.

As to the possibility that by further government intervention any tendency to a rise in prices might be counteracted under any existing economic situation confronting governments at this time, I will say that, of course, governments can do almost anything; but, in the first place, governmental policies tend in the longer run rather in
317 the direction of the raising of prices than in the opposite direction. At least, that is the purpose in most countries, and certainly in this country. Certainly there is no intentional tendency to lower prices in practically any country. Of course, they may lower prices by their policies in spite of their intentions in the opposite direction. They might do so by direct monetary measures, deflationary measures, such as a revaluation of the currencies—a revaluation to a major extent—which we discussed yesterday and which I regard as extremely unlikely, if not practically impossible, in view of the unpopularity of any such deflationary measures, especially in periods of low or falling prices. They may do so unintentionally by following the course of national and international policies which work themselves out as inhibitions to investment activities and to speculation.

There is, of course, no way of exactly predicting, and that is one reason why I am reluctant to make a prediction such as saying that next year, or in ten years, prices must rise. They would rise, in my opinion, if no national or international policies would interfere with them. On the other hand, I do not believe that national or international policies can be carried any such further period in the same

direction without breaking down, without being reversed or altered to such an extent as to permit or even to foster rising prices. All interests involved are so strongly focused on the upward trend of prices—all organized interests, I should say, all politically influential interests, in practically every country in the world—that I am at a loss to believe that governments could get away for a further major period with policies that would interfere with that possibility, namely, with a rising price situation.

Of course, as I say, there is no way of exactly predicting the course of government policies, but almost nothing short of changing the structure of our society, our economic society, changing it in the direction of something so radical as exists, for example, in present-day Russia, could, in my opinion, interfere for such lengths of time with the tremendous pressure in the direction of an upward surge of prices arising out of the monetary and credit situation and the related factors.

Questions by the Examiner.

As to the year base for the various indices, I do not have the wage index for gas workers here. I have not the volume of the National Bureau with me, and I have only their absolute figures present, not the index numbers computed from those. I will have to check into that and provide the data for the Commission later on cross-examination.

(EXHIBIT NO. 67 for identification, offered and received in evidence without objection.)

Cross-Examination by Mr. Booth.

I prepared these exhibits, together with an assistant, in so far as they were not reproductions of other charts published elsewhere, in which case they were checked. The Sauerbeck index is published currently in the London Statist. I reproduced it from a Belgian publication and checked on the specific data to check its correctness
318 with the Statist. I reproduced this from the study of Professor Demeure, Professor Charles S. Demeure, which appeared in the March, 1939, reports of the Belgian Society of Political Economics. Professor Demeure is an outstanding expert in the field of gold and price level

studies, and I took his chart on the subject and checked on it and used it. I also took the U. S. Bureau of Labor Statistical index from that chart because he had recomputed it to the new base. I did not compute it to the 1891-1900 period; but I checked on a number of figures and found it reliable. I cannot refer to any United States Bureau of Labor publication which uses the period 1891-1900 as 100; this is recomputed from that source; I did not compute it. I used the Demeure figures and checked on them partly, and I believe, until proved to the contrary, that they are correct; but if they are not, then he carries the blame. I have here a publication of the U. S. Department of Labor, Bureau of Labor Statistics, on wholesale prices. In that volume the index number of 100 is on 1926 prices. These give the data from 1801 to 1931.

My employment with the firm of Stein & Roe was in a rather informal fashion as their adviser, especially on international matters. They asked me my opinions on developments and their potential effects on markets, which they in turn used for their customers for advising them on that subject.

I am also economist for Stifel, Nicolaus & Company in a general fashion, with two major duties. One is that I publish for them occasionally what you would call market letters, though they are not really market letters. They are letters on subjects of general economic interest, which they circulate amongst their customers. The last one was on the question "Why Gold?" and there was one on cheap money policy, and others on similar general economic subjects. The other duty is a function that consists in requesting my opinion and discussing with me general factors affecting the markets, especially from the point of view of their and their customers' interests, such as interest rates, the markets affecting the municipals in which they are particularly interested, and similar problems. I do not have copies of those market letters I prepared with me. I do not doubt that Stifel, Nicolaus & Company will be glad to furnish you with copies. I will ask them to send them to you.

Cross-Examination by Mr. Slaff.

The assistant who helped me last summer was a Mr. Lewis, who, I understand, is now with the Brookings Institute in Washington, or he was recently at least. He is familiar with a part of my methods and underlying work

sheets, but not with all of them. There is no one in Chicago who is familiar with all my underlying data.

Several boys have worked with me at different times in the course of the year on different problems. Some of the sheets have been in the hands of different boys even who helped me on it. Lewis worked with me about three months on the major part of the job, but I had somebody else help me before, and two others are helping me occasionally since. None of them would be really familiar with the whole field, unless he would go into it. I would have to show him the whole thing and explain to him a lot, and I do not know which of them would be available during
319 the summer, anyway, either here or in Washington.

As to the names of the men here in Chicago who have assisted me in the preparation of these data, two of these young men are Mr. Proves and Mr. Glaser, both of whom are graduate students at the University of Chicago, in the sociology department.

I have testified before in this country. I once testified before the Interstate Commerce Commission on the problem of changing the time in Chicago, when the two newspapers fought here about the daylight saving time being extended over the whole year. They asked me to say something about the possible effect of changing hours on the financial market relations of Chicago to New York on the one hand, and to San Francisco on the other hand.

I usually do not predict price trends; and if I do, I do it in a very cautious fashion so that nobody can catch me. Well, certainly, I think our prediction as to price trends in the future as pretty much of a guess, but, seriously speaking, there are, of course, discernable underlying factors, and the moment you do not need to time your prediction precisely, there are possibilities of saying something about future probabilities.

320 CHARLES I. GALLOUP, a witness for defendants, testified as follows:

Direct Examination by Mr. Morgan.

(June 27, 1939.)

My name is Charles I. Galloup. I live in Amarillo, Texas. I am 48 years of age.

I am field superintendent for the Texoma Natural Gas Company, which position I have occupied since January 1,

1931. Prior to that time I was in the oil and gas business, strictly in the production end. I have worked in some thirty odd fields, in Kansas, Oklahoma and Texas, over a period of 32 years. I went into the oil and gas business at about sixteen years of age. I have worked in nearly every phase of production work, drilling wells, caring for them, and keeping them on production.

Prior to becoming production superintendent for Texoma Natural Gas Company, I had something to do with the production of gas in the Mid-Continent field in the three states I have mentioned. I have worked in thirty gas fields. By a field I mean an area which is productive of gas. Among the thirty fields was the Panhandle gas field.

When I was first employed by Texoma I was assigned to the duty of drilling and developing gas wells and caring for the production, and in case of non-production in a well, of plugging and abandoning it. I look after the well after it has been completed as a producer and see to it that it is kept in producing condition. I have drilled 110 wells for Texoma in the Panhandle. Some wells had been drilled prior to the time I took over the duties, and a number of wells were already on production. Since that time I have had general superintendence of the operation of all the wells that were already drilled and the drilling and operation of the wells which have been drilled since that time.

The most serious difficulty I have had to deal with in keeping the wells under my supervision down there in the Panhandle in a producing condition is salt water. Of the total number of wells belonging to that company, 26 have given me trouble with salt water. That is a condition that develops in the life of a well. The wells will salt up and become non-productive. That is the ultimate result.

When water first occurs it shows up on the orifice meter chart. By examining the meter chart I can determine that water has appeared in the well. When a chart begins to show a vibration, we go out and blow the well to determine whether it is making moisture. By "blowing a well" I mean that we close the side gate so that the gas does not enter the line leading from the well to the gathering system, and then the top valve is opened. That is a valve in the top of the casinghead on top of the well. It
321 is opened and the gas is opened to the atmospheric pressure and allowed to blow out into the air. After you have blown the well a short time, that is, five, ten or fifteen minutes, you will see a heavy spray of moisture,

which indicates that there is water coming in the well. As a rule, you continue to blow the well until it will clear up, by which I mean until the water that is in the well bore is blown out. Then the well is closed and turned back into the line of production. That temporarily operates to relieve the condition that has resulted from the inflow of salt water into the well bore.

You have to repeat the process of blowing these wells in which salt water has shown up as often as once a week when the well is on production. That does not serve as a permanent cure for salt water trouble in every instance. It is more or less of a temporary nature. It allows you to keep the well on production longer by taking care of it and blowing it.

The ultimate result where salt water gets into a well, if it comes in large quantities, is that it will drown the well out. The water pressure will equalize with the gas pressure and there will be no volume at all. In other cases of small amounts, the well bore will salt up in some cases, and in some cases the formation will salt up. There is a difference in the salting up of a well and the drowning out of a well. I have not had wells belonging to Texoma drown out since I have been in charge of their operations down there; but I have had some of the other development called the salting up of the formations. After wells start to salt up in the formation, the salting up or the crystallizing of the gas producing formation is a pretty fast process.

As to the effect this salt water has on the producing formation, which I have termed salting up, I will explain that the flow of gas with the small amount of water tends to dry up the water, and salt crystals form in the formation around the well. The gas moving to the well bore and out of the well bore in the ordinary course of production is the gas I refer to. It brings off a part of the vapor and leaves the salt behind. The salt will then be deposited in the formation, and oftentimes in the well bore itself.

It is my opinion and my experience that if the water comes into the well from above or below instead of coming from some other place through the formation to the well, it will salt off in the well bore, oftentimes above the gas pay. The result of the formation of that salt in the well bore is that it closes off the flow of the gas. This salting off in the well bore is always above the gas flow, because the gas carries it up there.

The development of salt accumulating in the well bore

above the producing formation is called a salt bridge. When a salt bridge has occurred in the well bore above the producing formation, a well on production will gradually settle out its deposits on the wall until it shuts the flow of gas completely off.

322 The salt in the bottom of the well forms only in the formation; that is, where water is coming in, traveling in the gas producing formation, sometimes it will carry a little up into the well, but it does not leave you very much to clean out in the well bore. The thing that stops the flow of gas where you have salt forming in the formation is that the salt deposits in the porous formation shut off the flow of gas. By that I mean that the vapor is evaporated off the salt water back in the formation away from the well, leaving the salt behind, back in the formation; and this closes off the porous formation through which the gas travels.

I have had such situations as salt bridging or the closing off or salting off of the production from gas wells in the Texoma wells under my supervision. I have had that occur on eight different wells. Not all of them were with salt bridges, some were a salting off in the formation; but it was one or the other.

As to when this salt water first showed up in those eight wells, I believe we had one well that showed salt water something over two years ago, and the others have started to show salt water within a year and a half. We have lost seven of those eight wells in the last year and a half.

The first well we lost was Bruce Bull No. 2-T, in Gray County. When my boys made a semi-annual test, they found that this well was dead. It would show a rock pressure, enough seepage through to show a rock pressure, but there was no volume there. That was sometime in the fore part of June, 1933, before the well was put on production or had a pipeline connection other than some lease use by the Texas Company. It was a well that had been bought from the Texas Company. We did not drill that well. We ran a measuring line to determine what had caused it. That is the cheapest way you can determine what was wrong with a well, and we found that the measuring line stopped at 1920 feet below the surface. A clean-out string of tools was then contracted for and moved on the location on November 18, 1933. We found after we had drilled enough to get a sample that it was pure crystal salt. That was a salt bridge. I believe that well was 2606 feet deep.

We found the salt some five or six hundred feet up the well bore.

We proceeded to drill the salt out just as if it were a formation. When we got 200 feet below where the top of the salt was encountered, we went through the salt bridge and it blew the tools out of the hole. This was gas which had been penned up down below which blew the tools out, along with the volume which we got back at that time. Before that well bridged up its potential capacity was twenty million. After we had drilled through that salt bridge and put it back on production, its potential was 19,300,000. It came back substantially to its original flow. That well was the Bruce Bull No. 2-T, Section 2, Block B-2, H & G N Survey, in Gray County, Texas.

This well continued to produce until in December, 1936, when it was reported off of production—that is, that it had quit producing. We went down and investigated and found that the well had no open flow and that it had a
323 rock pressure of 135 pounds per square inch. We figured that the same thing existed as had happened to the well before, so we moved a string of tools in there and cleaned the well out. This time, when we strung the tools in, we found the formation of something stopped the tools at 1910 feet, ten feet higher than it was before. We drilled far enough to get a sample and found it was the same salt condition as before, salted completely off.

We strung up eight inch tools, which was the full size of the well bore, and cleaned out to the top of the liner, but first we filled the hole full of water, because we did not want a recurrence of blowing the tools out of the hole, which is dangerous to life and the well might catch fire. Then we changed our tools from eight inch to 6⅝ inch and cleaned it out to the bottom of the liner, which was below or to the bottom of the gas pipe. Then we dried the hole up—that is, we bailed all the water out of it. There was no gas energy there to help us, so we bailed it out. We still did not have enough gas to measure. My opinion as to the reason for that and why it didn't come back on production as it did the first time is that the salt water coming into the sand had deposited the salt crystals and shut it off. The crystals had gotten far enough away from the well bore to shut it off. We found about 396 feet of salt in the bottom of the well at that time.

After we got the hole bailed out, in order to make sure to let the fresh water have a chance to dissolve the salt

crystals, if they were at the well bore, we went in with a tool called a ripper and we ripped two slots in each joint six feet long in each joint, starting at the bottom and going clear to the top. Then we ran enough water in the well to cover all of the gas pays—that is, we filled the well with fresh water up above the highest of the producing formations. It was left to stand over night, and the following morning it was bailed out, and then after the water was bailed out it was recharged with water and left standing there until the evening. We were just working daytimes on the clean-out wells.

We continued this type of treatment during each twenty-four hours for five days, with no results, except that when we re-perforated that pipe we had about 1,300,000 cubic feet, but the fresh water application did not restore any more production than we had there. We found just the same situation after those five days on injecting fresh water in the well and leaving it stand for successive periods of twelve hours as we did before we started.

That is the accepted way of treating a well which has been salted off. The analysis run at our chemical laboratory at Oil City showed that fresh water was about as good an agent as anything you could use to dissolve that salt and bring it out of the well. Ordinarily, if salt is confined to the rim of the well bore at an area immediately around that rim, the result of the fresh water treatment will be to restore production.

When we bailed the fresh water out from time to time we found that the well was very salty in the bottom.
324 We found fine crystallized salt in the bottom of the bailer, and either from the friction of dumping the bailer in the dump box or from the speed of raising the bailer from the bottom, it settled in the bottom of the bailer, and oftentimes the bailer would have to be up-ended instead of being dumped in the usual manner.

I don't know of any better way to treat a well that has been salted off than to use water. That is the way we have always done.

After five days of drenching the well with fresh water, we decided to plug and abandon it. By plugging and abandoning a well, I mean we reclaim all the material, such as casing, that we can, and leave the rest of it there and abandon it. The hole is filled with mud to a change in the size of the casing, where a dry hole plug is used. A dry hole plug is a wooden block made to fit the size of the pipe or

size of the hole at the point where you are going to stop the well. Then it has been our practice to dump cement on top of that plug. Then, in the other step, after that cement has had a chance to dry or set, the hole is filled with mud to the bottom of the next string of pipe, and the same steps taken, and a dry hole plug the size of the hole you are trying to stop is then run, and then it is cemented, until it reaches the ground level. When we have pulled all the casing and tubing in the well that we can get out of it, and have plugged it in these successive steps which I have described and filled it up with mud to the top of the ground, we call that a plugged and abandoned well. We never produce any more gas from that well. That is a permanent job and it takes that well out of the picture.

Mr. Peterson testified two or three weeks ago that seven wells had been plugged and abandoned by Texoma. He was not mistaken about that at that time. We have plugged one well since he presented his testimony.

The second well in which we had a similar experience in finding salted up was the G. H. Saunders No. 2-T, in Section 3, H&GN Survey, Gray County, Texas. Salt water showed up in that well some time in the latter part of 1937. We made a test of that well on May 1, 1938, and found the open flow too small to measure through a four inch opening. It had a rock pressure of 100 pounds, showing there was some seepage through the pay into the well. If a well gets into that condition and is shut down until you can get to it with cleaning out tools, there will be some gas accumulate in the well bore that will build it up to the pressure of that area if given sufficient length of time. You take your rock pressure test before the well is ever vented to the air, before it is ever opened so the gas in the well bore can get out. Then you open the well up, until the head pressure is blown off, and then you take your test after a period of thirty minutes in these cases. In this particular case it took around five or ten minutes for the gas to expel itself from the well bore. After that you could see some gas fumes coming out of the well, but there was no volume.

We moved a clean-out machine in to try to restore
325 production. We followed a similar procedure to that we had followed with the other well, but this well was not bridged. It evidently was salted off in the formation. We found a crystalline salt in the bottom. It had possibly twenty feet of stuff to clean out. We cleaned it out and

gave it a fresh water treatment as we did in the other well, at the same intervals and for the same number of days; but we were unable to increase the flow of gas, so we plugged and abandoned that well.

(Map entitled "Leases Owned by Texoma Natural Gas Company in Texas Panhandle Gas Field, January 1, 1931," marked Exhibit No. 68 for identification.)

Exhibit 68 is now before me for the purpose of locating the wells to which I have referred. Penciled rings can be put around the wells referred to.

Bruce Bull 2-T is located in Section 2, Block B-2, H&GN Survey, Gray County, Texas.

Saunders 2-T is located in Section 3, H&GN Survey, Gray County, Texas.

G. H. Saunders 3-T is located in Section 3, B&B Survey, Gray County, Texas.

G. H. Saunders 15-T is located in Section 4, Block 1, A.C.H. & B. Survey, Gray County, Texas.

Saunders 17-T is located in Section 3, Block 1, A.C.H.& B. Survey, Gray County, Texas.

Saunders No. 18-T is located in Section 3, Block 1, A.C. H.&B. Survey, in Gray County, Texas.

McLarty-Lester B-I-T is located in Section 2, B&B Survey, Gray County, Texas.

M. A. Shaw 1-T is located in Section 5, Block 1, A.C.H. &B. Survey, in Gray County, Texas.

Those wells are all located north of the straight line of the depression area in Gray County.

I have said that there were eighteen wells that had started showing water. I will read them off, starting on the east side and moving west.

H. Thut No. 1-T, Section 1, H&GN Survey, Gray County.

Saunders 13-T, Section 1, J. G. Eustis Survey, Gray County.

Saunders 12-T, Section 1, J. G. Eustis Survey, Gray County.

McLarty-Lester No. 3-T, Section 10, ACH&B Survey, Gray County.

Saunders 6-T, Section 4, Block 1, ACH&B Survey, Gray County.

Saunders 10-T, Section 1, J. G. Eustis Survey, Gray County.

Moore No. 1-P, Section 14, Block 44, H&TC Survey, Moore County.

Purvis No. 1-T, Section 151, Block B-2, H&GN Survey, Gray County.

Barrett No. 1-T, Section 131, Block 3, I&GN Survey, Gray County.

326 That takes in all of Gray County. The last two were about half way between the county line and the depression area in Gray County. The first ones were shown in the general area heretofore described. I will now list the ones in Carson County.

J. H. Urbanczyk No. 1-T, Section 25, Block 4, I&GN Survey.

N. A. Cobb No. 1-T, Section 202, Block 3, I&GN Survey.

W. E. Cobb No. 1-G, Section 202, Block 3, I&GN Survey.

Henry Schafer No. 1-T, Section 68, Block 4, I&GN Survey.

McEwen No. 1-G, Section 204, Block 3, I&GN Survey.

Burnett No. 11-G, Section 106, Block 5, I&GN Survey.

Burnett No. 19-G, Section 106, Block 5, I&GN Survey.

Burnett No. B-1-G, Section 21, Block 5, I&GN Survey.

In Moore County, in addition to Moore No. 1-P, Section 14, Block 44, H&TC Survey, which I have already listed, there are:

Troutman 1-S-P, Section 273, Block 44, H&TC Survey.

J. T. Sneed No. 1-P, Napoleon Jones Survey.

I have already given you my experience on the Bruce Bull No. 2-T and the Saunders No. 2-T. I will briefly give you the name and location of the other six wells which went dead and were plugged and abandoned.

The G. H. Saunders No. 3-T, in Section 3, B&B Survey, in Gray County, Texas, had a rock pressure of 135 pounds and an open flow too small to measure.

The G. H. Saunders 15-T, located in Section 4, Block 1, A.C.H. & B Survey, Gray County, had a rock pressure of 135 pounds and an open flow too small to measure.

G. H. Saunders No. 17-T, in Section 3, Block 1, A.C.H. & B. Survey, Gray County, had a rock pressure of 130 pounds and the volume after the work was about 300,000.

G. H. Saunders 18-T, in Section 3, Block 1, A.C.H.&B. Survey, had a rock pressure of 140 pounds, with an open flow of 150,000.

McLarty-Lester B-1-T, in Section 2, B. & B. Survey, Gray County, had a rock pressure of 100 pounds and an open flow of 500,000, after the clean-out work.

M. A. Shaw No. 1-T, Section 5, Block 1, A. C. H. & B.,

had a rock pressure of 145 pounds and a volume of 304,000 after the clean-out work.

The rock pressures stated by me ranged from 100 pounds to 145 pounds at the time of abandonment. Those are not the official Railroad Commission pressures to which Mr. Peterson testified when he was describing the wells which had been plugged and abandoned. These are the rock pressures that I took myself. The pressures to which he referred were the official Railroad Commission tests at
327 the last testing time prior to abandonment. If they can get around to make them, those tests are made twice a year; if they don't they are made once a year.

I had the same kind of reports made to me in connection with each of the other six wells as the reports given in connection with the Bruce Bull and Saunders 2-T. Upon receiving the reports in the case of each well, we checked them and found they were right in every case, and we found the conditions in the well to be as stated. Each time we took the same steps that we took in connection with the two wells I have described, but with no results, and we had to plug and abandon the well in each case.

I have stated that we have eighteen other wells which are now showing water. We watch them closely to keep them blown, so that a head of water does not get in there. We do not allow the water to accumulate in the well bore. From my experience down there, I think that we can expect in time, when the pressures are considerably lower than they are now, or equal with the other parts of the field, that the same thing will happen in each of those wells as has happened with the eight wells which we have plugged and abandoned. By saying when the pressure is reduced, I mean that without the pressures it is almost impossible to keep the formations open. The fall in the pressure tends to cause water to get back into the producing formations. It seems to spread out.

In common parlance, the area where those abandoned wells are is in southeastern Gray County. The pressures in that area are low and have been low for the last two or three years, and during that time the water trouble has shown up. In my opinion, when these other 18 wells are given time, with the influence of low pressures operating along with time, they will go the same way as those eight wells.

This is only 26 wells out of a total of 161 wells. I have no idea whether the other wells may develop water trouble

in the future. We did not expect it in the wells it has shown up in. It is apt to show up in any well. There is not water in all of the gas wells; but there was no water in those wells which are now showing water at the time they were completed as gas wells. Those wells which I myself drilled and which are now showing water were completed in the best known way. We drilled deep enough to get all the production; but we did not drill them deep enough to get into water. They were all stopped over the water level. When they were completed they were dry and in perfect shape. It was an average of about two and a half or three years after they were put on production before water began to show up. I don't know where the water comes from.

In drilling wells down there you run through the general formations from one end of the field to the other. You get your salt lenses and your water in the various places according to the elevation. There is water above the Big Lime in every gas well down there.

If a well be drilled down through water in the vicinity of a well belonging to Texoma, there is a possibility that water will get from the other well into the Texoma well, even
328 though the latter has not been drilled down to water.

That might occur because the water rises up, and as soon as it gets to the porous formation it starts traveling. That occurrence is more likely where the pressures are reduced than where they are high. In the light of that situation, it is possible that the other 130 or 140 wells which are not showing water will make water when the pressures drop down.

I have stated that I have worked in some thirty gas fields in the States of Kansas, Oklahoma and Texas. Some of those gas fields had water conditions comparable to those obtaining in the Panhandle. I have experienced this phenomenon of having a well become so salted up in the formations that it cut off production in places other than in the Panhandle. I have experienced that same situation in the Eldorado field and the Augusta field in the State of Kansas. The same method was adopted in handling those wells there which we adopted in handling the Panhandle wells which were abandoned. Those are older fields than the Panhandle field. There are some few wells in the Augusta and Eldorado fields which are producing gas yet; but the majority of them have been plugged and abandoned. I haven't the dope on the prevailing pressures in the Augusta field; but I have seen a report recently on the El-

dorado field, which was that the abandonment pressures averaged 93 pounds. I was present when some of those wells were being abandoned. They were in such a condition that they would not produce any more gas, and remedial work was unsuccessful, and they were abandoned.

Based on my experience and observations in those fields and in the Texas Panhandle field, it is my opinion that the pressure to which the Texoma wells in the Panhandle will be produced will probably be an average of 100 pounds.

Cross-Examination by Mr. Slaff.

I was never on the witness stand before in my life.

I said that I had seen a report which showed the abandonment pressures in the Eldorado field to average about 93 pounds. One of the boys I used to work with up there had a report. I don't know just how many wells he had on it, but there was quite a number of wells that had been plugged and abandoned in 1937. I couldn't say whose report that was. I imagine the field man there made the report. It probably can be obtained from somebody's report. They don't have a Commission's report in Kansas. I can find out whose report it was and advise you through counsel. I will do that.

Questions by the Examiner.

It is the uniform practice to plug and close wells that are no longer being used for production purposes. I don't know whether they have to do that under the state law, but I believe they do. The lowest pressure we have in a Texoma well today is around 140 or 130. We have no well of low pressure that is not without water conditions. We have wells with even high pressures that do show some water conditions; but it is the low pressure wells we have had the most severe trouble with and had to abandon. All
329 of the water is not salt water. Some of the wells would be comparable with water conditions where the water contains no salt at all. It is condensate. You can't acidize a salt well. They have attempted to do that, but with no results.

Redirect Examination by Mr. Morgan.

I spoke of condensation of fresh water. That is not the kind of water that is in these eighteen wells about which I have testified. That is salt water in every instance. I did not include this condensate among my list of water wells.

(Note: On July 24, 1939, EXHIBIT 86 was offered and received in evidence by defendants over objection by counsel for Illinois Commerce Commission as being hearsay. This exhibit is a report referred to by Mr. Galloup in his testimony as having been received from F. D. Frank, Superintendent of Operations of Cities Service Gas Company, dated July 6, 1939, and showing in tabulated form the open flows and rock pressures on the wells abandoned in the Eldorado and Augusta fields in Butler County, Kansas. This exhibit was offered in evidence as being that to which Mr. Galloup referred in his testimony when he said he had obtained information from other sources as to the abandonment of wells in the Eldorado field. This report was not offered as proof of anything but in compliance with a request made by counsel for the two commissions to produce the report.)

330 E. G. HAMMERSCHMIDT, a witness for defendants, testified as follows:

Direct Examination by Mr. Morgan.

(June 27, 1939.)

My name is E. G. Hammerschmidt. I live at Fritch, Hutchinson County, Texas; at the gasoline plant and compressor station of Texoma Natural Gas Company. I am chief chemist for that company.

I received my education in the field of chemistry. I graduated from Culver Military Academy in 1917, and attended Hendricks College, Conway, Arkansas for one year, and graduated from the University of Iowa in 1923 with the degree of Bachelor in Chemical Engineering.

After graduation I was with the Cities Service Gas Company for approximately eight years, beginning in the fall of 1923, stationed at a high pressure gasoline plant for approximately two years; transferred from there into the Steel Pool in Kansas, at a casinghead gasoline plant; and

transferred from there to the chemical department at Oil Hill, Kansas, near Eldorado. After about eight months I was transferred to Tallant, Oklahoma, in the chemical research department. At the termination of that period I entered the employ of Texoma Natural Gas Company at Fritch, Texas, in August, 1931.

Prior to my employment by Texoma my work was in the nature of chemical research. We were working on a process for partial oxidization of natural gas to form various constituents for four months immediately preceding my employment by Texoma. That consisted for the most part of research and development work, which resulted in the establishment of a plant at Tallant, Oklahoma.

In connection with my research I had occasion to measure gas in small quantities, and since I went with Texoma I have had occasion so to measure gas. It is a part of my routine to do that from time to time.

When I first went with Texoma there was a certain amount of control work to do in testing the gas as it goes through the station, as well as the gas and water from various stations along the line on the way to Chicago. This test is for a number of different purposes. We make some physical tests, such as for specific gravity, testing for heating value, sulphur content of the gas, and for water; and, of course, certain tests are made of the cooling system water to determine the fitness of the water for use at the stations, for corrosion possibilities, and various other factors. These routine matters involve the measurement of gas.

Since I was employed by Texoma we have always
331 had a certain amount of research and development work to do. One of the first things was the study of gas hydrates. This is a compound of gas with water that forms a solid compound, which melts, depending upon the temperature and pressure. In general, the higher the pressure on the system, the higher the melting point; the lower the pressure, the lower the melting point.

A gas hydrate may look like ice, or it may look like snow, depending on the way it is made. In the pipeline ordinarily it has the appearance of snow. It is crystalline. It has an appearance of something like cones of a fir tree. It is a branch of crystal.

When I went to work for Texoma we did not know that hydrates existed. The gas industry had had trouble for years with freezing in the pipelines, but up until 1931 it had been attributed directly to ice accumulations in the

line. It was necessary for Texoma to make special research into that field because at the time the line was built Texoma had installed a plant at the Fritch station for the purpose of removing water from the gas so as to eliminate freezing troubles in the line. This plant was so designed that the gas would be chilled and thereby condensing out the water and allowing the dry gas to go downstream, so the condensate trouble would not occur on the downstream side.

When this plant was placed in operation we found all sorts of trouble occurred in thet coils of the cooling units, and it was necessary to shut down a unit after it had been in operation for a short time, and defrost, like they do an ordinary ice box, in order to operate at its maximum capacity again.

The problem demanded original research work in connection with the operations of Texoma because they were operating at higher pressure than most other gas lines, and, as stated before, the melting point of these hydrates is higher with the higher pressures. We were obtaining melting points in the vicinity of 50 or 60 degrees Fahrenheit, instead of 32, as for water.

Prior to the building of this plant, the industry had encountered this same trouble with the higher melting point, although they did not realize it at the time. The difference in the conditions under which we proposed to operate the Texoma lines from those of the ordinary gas line was that Texoma desired to operate at a maximum pressure of 800 pounds, which was considerably higher than the usual pressure at which gas lines were operated at that time. Then the ordinary pressures at which gas lines were operated were from 150 to possibly 300 pounds, and you do not encounter an accumulation of these hydrates at pressures of 100 to 300 pounds in ordinary weather.

The accumulations in these lines which turned out to be hydrates had not been identified as hydrates at the time the Texoma plant was put in operation. They were then believed to be ordinary freezing of water in the pipelines by temperatures low enough to freeze water. In the beginning,

in order to stop the freezing of its lines, Texoma in-
332 stalled a dehumidification plant at the Fritch station for the purpose of removing water. I believe that is the first plant ever installed by a natural gas pipeline in a natural gas field. The work which resulted in the identification of this substance which formed in the Company's pipe-

lines as hydrates rather than ice was done by me in the Fritch laboratory.

I have been asked to submit for publication several papers or studies in the field of gas hydrates. Those publications, the name of the article, and the date published, are as follows:

"Moisture Content of Natural Gas," published by Western Gas, December, 1933.

"Formation of Gas Hydrates in Natural Gas Transmission Lines," in Industrial Engineering Chemistry, Volume 26, pages 81 to 85, in 1934.

"Moisture in Natural Gas," presented before the Southwestern Gas Measurement Short Course at the University of Oklahoma in April, 1935, and later published in the Oil & Gas Journal, June 20, 1935.

"Gas Hydrates," presented as a paper before the American Gas Association in Dallas, May, 1936, and later published in the American Gas Association Monthly, in the July, 1936, edition.

A paper on "Preventing and Removing Gas Hydrate Formations from Natural Gas Pipelines," presented at the May meeting of the American Gas Association this year; later appearing in Gas Age, Volume 83, page 45; also in Gas for May, page 30; also in the Oil & Gas Journal for May 11, 1939, page 66.

I have been asked to describe the formation of that hydrate in a gas pipeline where the water is not removed, the behavior of the hydrate as it forms, and the result of its being formed in that formation. As the gas comes from the well and is compressed, ordinarily it is saturated—that is, it holds as much water vapor as it can. Later on, if the temperature of the line drops and there is moisture in the gas, some of the moisture will condense. If the pressure and temperature conditions are right for the formation of hydrates, this moisture will form as a hydrate instead of liquid water. That, of course, will depend upon the temperature and pressure. At about 800 pounds I think that the temperature melting point will be about 60 degrees Fahrenheit, and it decreases as the temperature of the line decreases.

With ordinary water condensation the amount of water that condenses in a pipeline will depend on the vapor pressure of the water. We have a state of equilibrium set up there, in which you get a certain amount of water condensed and therefore a certain amount of water left above

the liquid water. After equilibrium has been obtained, no more can be condensed for any given pressure and temperature.

When this hydrate forms, having considerably lower vajor pressure than water, additional water can be
333 absorbed, if you want to look at it as absorption, and these hydrates in the pipeline block it up more rapidly due to the melting factor, and also due to the factor that it is bulkier and takes up more space, as snow takes up more space. This reduces the capacity of the pipeline and may entirely shut off the flow. That experience has actually occurred, where the pipeline has been so stopped with hydrates as partly to cut off the flow or to cut it off entirely.

During the past three weeks I have been requested to conduct some tests in the field of the solubility of gas into oil down there in the Panhandle. I am familiar with a bulletin of the Bureau of Mines in which some curves are set out showing the solubility of certain gases with certain oils prepared by Dow and Calkin. I have examined that bulletin and am familiar with the curves. I know how the curves were constructed by the authors of the pamphlet and on what information they constructed it.

They had a container to which they added crude oil, among other things—they used a number of different circumstances—and above the crude oil they introduced a certain amount of natural gas at various pressures. One test would be made in this manner: They would decide on some definite pressure and temperature, and they would add gas to this cylinder until it had attained this pressure of, say, 200 pounds, and they would saturate the oil with gas; that is, they would keep adding gas to this cylinder until the pressure remained constant at, say, 200 pounds. In other words, a state of equilibrium existed between the gas and the oil at a definite pressure and temperature.

They would then liberate the pressure in this bomb and measure the gas coming out of solution, and in this manner they were able to establish one point of the gas-oil ratio curve. In this particular method of determining the gas-oil ratios they made measurements for each different pressure of any given gas and oil sample until they had established a uniform point where they could build the entire curve of pressure versus the cubic feet of gas dissolved per barrel of oil.

They took oil which no longer contained gas and dis-

solved gas in it by the chemical process I have described until it reached the saturation point, and then the gas was withdrawn and measured as it came out, and in that way they arrived at the quantity of gas which had been received in solution.

We made such a test in the Panhandle, using Panhandle oil and Panhandle gas. The oil was a sample from a stock tank at the Alamo refinery of the Phillips Petroleum Company, one that was a mixture of oil from Gray and Hutchinson Counties. The gas was a composite sample from Texoma's compressor station covering the area of the Panhandle field in Moore, Hutchinson, Carson, Gray and Potter Counties. With those samples we did precisely the same thing that was described by Dow and Calkin in this pamphlet we have discussed. We dissolved this gas in the oil at different pressures, and at a temperature of 90 degrees, and established a similar curve to this, showing gas-oil ratios compared with the pressure of the sample. We saturated the oil under such circumstances that we
334 were able to ascertain how much it would contain at
471 pounds absolute. At 471 pounds absolute we obtained a gas-oil ratio of 94 cubic feet per barrel, on a pressure base of 14.7 pounds; but we changed that to 16.4, which will lower it to about 85 cubic feet per barrel. We used 471 pounds as the basis for our computation because that is the initial rock pressure of the oil field in that vicinity.

We were not satisfied after having made that test that we had arrived at the correct amount in terms of cubic feet of gas to the oil in the formation at a pressure of 471 pounds in that field, because in obtaining a sample of stock tank crude oil certain of the volatile vapors have been removed from that oil. In other words, it is not the same as it was originally; and in the same way the dry natural gas which was used in this sample had some of the higher boiling constituents missing from it, so in a composite sample of this kind, with a mixed oil sample and a gas sample, there is a gap in between them.

We did not stop our investigation when we followed the same procedure that had been followed by Dow and Calkin. We went further and obtained additional information. I prepared a curve showing the results of that test, and I have the base figures from which that curve was constructed.

The tests referred to were made at the research laboratory of the Phillips Petroleum Company at Bartlesville, Oklahoma. I was present and witnessed the compositing of

the samples and the later analyses that were made on the composite. The steps taken in the course of making those tests are outlined in the following statement.

We had a steel sample bomb that was first filled with mercury entirely and a crude oil sample from this stock tank. Crude was poured into this top portion of the bomb, removing an equivalent amount of mercury at the bottom, after which the gas was added from the top part of the bomb. The oil was saturated with the gas and it was necessary in this particular test to try to saturate the gas at 471 pounds. We had to take an indefinite amount of gas into this cylinder. We did not know how much, of course, and in the sample shown here on the curve sheet we actually got a great deal more gas in there than we thought we would get at 471 pounds. That was accomplished by adding gas to the top of this bomb at our cylinder pressure, which was approximately 700 pounds, and then compressing by pumping mercury into the bottom of the bomb until all of the gas had gone into solution. We did that by compressing the sample up between one and two thousand pounds to be sure all the gas had gone into solution, and at the same time we rocked this bomb, which would allow the mercury to slosh back and forth and insure thorough mixing, and then after the sample was brought into solution it was further checked by determining the vapor pressure. The highest point on this curve is the vapor pressure of that sample after the sample had been mixed up in that manner. It was then placed in a constant temperature vat held at 90 degrees Fahrenheit, still under about 2000 pounds pressure, and a very small amount of mercury was liberated from the bottom portion of this bomb,
335 which amount was recorded, and, of course, this little amount of mercury would allow a fairly large decrease in pressure, because mercury is not very compressable.

We continued that for a number of steps, until we reached a point where gas began to come out of solution. Then if we plot mercury, the amount of mercury drained out versus the pressure drop, we would get a very steep line coming down to begin with until the gas begins to break out of solution, in which case we get a very sharp break in the other direction. The point of intersection of those two lines is taken as the vapor pressure. That

is the top point which we have on the curve here. It was 975 pounds in this case.

Starting from that point, then, we began to liberate gas from the bomb, measured the gas as it came off and the corresponding reduced pressure, and did that in several steps shown by the certain points on this curve, until we reached atmospheric pressure.

This samplying bomb, this container of the gas-oil mixture, is constructed so that the inside of it contains a spring, to the end of which is attached a weight, and this whole apparatus then is shaken and moved up and down so that this spring and weight will agitate the oil in the bottom. It is quite difficult to establish equilibrium conditions, as we attempted to do in making this test. We lower the pressure to a given point and measure the gas that comes off at that pressure.

We can lower it to, say, 725 pounds on this first step, shake it, and it will jump right back up nearly to the full pressure. We continue shaking that then until there is no change in pressure, thus showing that there is no more gas coming out of solution. That amount of gas, then, is the amount that is vaporized at this pressure point on the curve, and then we go down to another lower pressure point and measure the gas that comes off at that point, and when all the gas has been so evolved this gas-oil ratio here can be constructed.

The purpose of jostling or shaking that I have spoken of is this: You can liberate pressure on a mixture of gas and oil, where gas is dissolved in oil, and it will not establish equilibrium conditions immediately. In fact, there will be a long period of delay unless you speed that up by some method, such as agitating the mixture. That is what we accomplished by this spring device which I have described.

The gas goes into the solution by chemical absorption of the particles of the gas in those of the oil, and it is only the exposed part of the oil that is in touch with the gas at first when it is in a static condition. The stirring or the jostling of the oil up through the container where the gas is affects the absorbing of the particles of gas in the particles of oil by giving it a greater chance of exposure to the different portions of the oil. It is the same principle as stirring the coffee in order to absorb the sugar in it. That would be an analogy.

336 In the course of the test we agitated the oil a great deal. We were able to insure all the gas had gone into solution by compressing it to a point far beyond its vapor pressure.

(Document entitled "Solubility Curve," marked Exhibit No. 69 for identification.)

Exhibit 69 entitled, "Solubility Curve," was prepared by me, and I am now marking on it the quantity of gas that I found could be dissolved in that oil, measured on a pressure base of 16.4 pounds per square inch. The notation now made is the addition of "85 cubic feet per barrel at 16.4 pounds per square inch."

(EXHIBIT NO. 69, for identification, offered and received in evidence without objection.)

As I have said, we were not satisfied with the test as indicating the solubility of gas in oil in the formation at the original pressure in the Panhandle because of the manner in which we composited these samples of oil and gas, which did not take into consideration the effect of the vapors that had been evolved from the crude oil together with certain heavier hydro-carbon constituents that were missing from the natural gas that we might normally expect to be in equilibrium with crude oil under bottom hole pressure conditions and temperature conditions.

In an effort to find the answer to the question of how much gas could be and probably was dissolved in the crude oil in the formations in the Panhandle at original pressure, we obtained some actual bottom hole samples of Panhandle crude oil in its natural state. Through a cooperative arrangement with the Phillips Petroleum Company, which has available certain specialized equipment for obtaining these samples, we were able to take the samples at the bottom hole pressures and temperature conditions.

This equipment consists essentially of a tube that will go down into the well. It has a valve on either end, both of which valves are cocked open at the time it goes into the top of the well. The sampling tube is then lowered to the depth at which the sample is to be taken, and the sample tube is washed out by raising and lowering it in the well, after which, by a device that is controlled from the top of the well, the valves are thrown shut. The sample then is locked in this device. It is

raised to the top of the well where it can be checked to be sure that no leaks have occurred, and in that way it can be transferred to a sample vessel, where it can be removed to a laboratory for further testing.

Several samples were taken. One of them we were able to lower right down on the bottom and obtain a bottom hole sample. On some of the others we came up off the bottom a little bit in order not to get any water in the sample tube. Some of the wells have water down below the oil in the well bore. Of course, we had to send a bailer down to begin with, to be sure there wasn't any water at the depth where we planned to take these samples. One of the wells showed no water at all, so we were able to go clear to the bottom of the hole.

Those samples were taken in the Panhandle oil field, in Hutchinson County, from wells of Phillips Petroleum Company. They were taken from Cockerell No. 41, in Section 6, Block M-21, which is an oil well. In this 337 particular well there was no gas. It is in the sour gas zone, however, and the oil is sour. The second well was Cockrell No. 36, in Section 3, Block M-21. The Juanita Johnson No. 4 is 320 feet north and 530 feet east of the West ½ of Section 5, Block 1, Brooks & Burleson Survey. The crude in that well smelled sour that day. The E. B. Dorset No. 1, in Section 64, Block 46, H&TC Survey, is also north of the sour gas line.

We went through the same procedure in obtaining samples from each of the other three wells. The sample bomb came out of the well full of oil under conditions so that its pressure was not reduced in the process of bringing it out. It was brought out in the original condition it was in at the bottom of the hole, and had exactly the same pressure when we got it outside of the well as it had down in the bottom of the well, unless the atmospheric temperature increased the pressure by increasing the temperature on the tube, but nothing would leak out of it.

We transferred those samples to sample containers so that they could be removed to the laboratory for further analysis. We did that in this way: This tube that I have attempted to describe has a removable head on one end. That is on the top side of a valve. I have a drawing of it here that may help a little in following that. The top portion there is unscrewed and a new type head is

put on. This head has two openings, to one in which is attached a mercury pump, and to the other one is attached the sampling tube. The head is filled with mercury, as well as all the lines leading up to it. Mercury is pumped into the bomb. Of course, the bomb is full and the pressure immediately rises, and the pressure on this bomb is placed far above its vapor pressure, so there is no possibility of any gas coming out of solution of the oil during the transfer of the sample. We pumped those up to between one and two thousand pounds before the valve on the bottom hole sample tube was ever opened.

The mercury then was pumped into the sampling tube and the transfer cyclinder valve was opened, which was also full of mercury, and as the oil was brought over into the sample container the mercury was withdrawn from the bottom of this container. When a sufficient amount of sample had been withdrawn, both valves on the transfer container were closed. The lower valve then was constructed to allow some more mercury to run out, which would allow expansion space in the sample container. This, of course, would allow gas to form above the oil and mercury in the bottom, but then it is closed up, both valves are closed, and this gas was later brought back into solution when it was taken to the laboratory. After it was sealed up in that new container it was taken to the research laboratory of the Phillips Petroleum Company in Bartlesville, Oklahoma. We didn't take it to the Fritch laboratory of Texoma because the method of completing the test required specialized equipment which we did not have at Fritch, and for that reason we arranged to take it to the Phillips Petroleum Company laboratory, which did have such equipment already on hand.

That is the same kind of equipment which is com-
338 monly used for the purpose of taking bottom hole samples from oil wells, and the method we employed after the samples were removed from the wells is the commonly accepted method of handling oil thus removed from the bottom of a well in order to get it to a laboratory.

As to where I learned that such a test could be made, this bomb is described in this report of investigations, No. 3212 of the Bureau of Mines, published in May, 1933.

I was out there when they began to prepare for taking

the samples and stayed with them throughout all the taking of the samples, and after the last samples had been taken I put them in my car and took them to the Bartlesville laboratory. I saw every step that was taken and know that it was taken according to the accepted manner of doing it.

After we got the samples to the laboratory at Bartlesville, Oklahoma, the gas-oil ratio was established at the bottom hole temperature of each sample in this specialized piece of apparatus of which we have spoken. This was done in practically the same way as that already described, with the exception that we did not have to mix up our sample because we already had the sample mixed, and all we had to do then was to transfer it again to the testing apparatus, insert it in the constant temperature vat, and withdraw consecutive portions of gas as the gas was removed from the oil upon reduction of pressure in successive steps down to atmospheric pressure. We measured the temperature of the oil at the bottom of the well at the time the sample was taken. Cockerell No. 41 was 88 degrees Fahrenheit; Cockerell No. 36 was 89 degrees; the E. B. Dorset was 83 degrees; and the Juanita Johnson was 89 degrees.

Going back to the laboratory at Bartlesville and describing how the process of testing the content of these samples was accomplished, I will point out to start with that we established the vapor pressure of the oil sample in the same manner that has been described on this other gas-oil mixture, by withdrawing mercury in small amounts until we had reached a point where the gas began to break out of the oil. On the Cockerell No. 41 that was 425 pounds per square inch absolute at 88 degrees Fahrenheit. From that point we reduced the pressure to in the neighborhood of 325 pounds, and by continuous shaking of the apparatus we evolved all the gas that would come out of solution of the oil at that temperature and pressure.

It was necessary to shake the apparatus because it is quite a difficult matter to get all of the gas to come out of solution unless it is thoroughly agitated. It tends to supersaturate, if you want to look at it that way. You lower the pressure and instead of all that gas immediately coming out that should come out under equilibrium conditions, a good bit of it stays in the oil, so we had to agitate the oil in this container until there was no more gas evolved, as was indicated on the pressure gauges on the apparatus.

We measured that gas as the pressure came down and constructed a curve so as to determine just how much
339 gas came out of solution as the result of this test and the agitation of which I have spoken. After we had gotten all the gas out that we could at one pressure, that pressure was recorded together with the total volume of gas that had been withdrawn to obtain that pressure.

We then dropped the pressure down to obtain another point on the curve, obtaining several different points, until all of the gas had been evolved from the container, shaking it at each interval, as described before. I might add that when we got down to the lower pressures, the last set, we seemed to have more trouble in getting that gas to come out of solution than we did at the higher pressures. I do not know why it was; but we were not able to remove the last bit of that gas without agitating and shaking that container sometimes for as long as 45 minutes. There is an element of time required to get the gas out as the pressure goes down.

We went through the same process, from the taking of the sample to the completion of the test, in the case of the sample from each of the four wells.

When the pressure had gotten down to 50 pounds, we found in the case of Cockerell No. 41 that there was about 87 cubic feet per barrel remaining in solution in the oil. In the case of Cockerell No. 36 and Juanita Johnson No. 4 we had about 60 cubic feet per barrel remaining, and in the case of the E. B. Dorset about 26 cubic feet per barrel.

I have a tabulation of the data and information prepared in such a way as that it can be conveniently presented.

(Document entitled "Bottom Hole Sampling Data," marked Exhibit No. 70 for identification.)

This exhibit contains a description of the samples that were taken, the bottom hole samples, together with the bottom hole temperatures and pressures which were measured at the time the samples were taken, and the location of the samples, together with a summary of the gas-oil ratios that were found after these samples had been returned to the laboratory for analysis.

In the last line of the tabulation, before getting to the description, there is a line "Gas-Oil Ratio at 456 Gauge Cubic feet Per Barrel." 450 gauge was used because that is equivalent to 471 pounds absolute. These tests, of course, are all measured with that gauge pressure and recordings are given at gauge pressure and corrected back to 471

pounds absolute. The pressure base on which the gas was measured as it came out of the oil was 14.7 pounds. The gas-oil ratios contained in those four columns can be stated in terms of gas measured at 16.4.

We found the gas contained in the reservoir corrected to original reservoir pressure of 471 pounds, measured on a basis of 14.7, was 209 cubic feet on the Cockerell No. 41; 183 for the Cockerell No. 36; 86 for the Dorset; and 170 for the Juanita Johnson. Correcting that to a base of 16.4 pounds per square inch, we find for the Cockerell No. 41, 187; for the Cockerell No. 36, 164; for the Dorset, 77; and for the Juanita Johnson, 152. There will also be a corresponding change in the line immediately preceding that, showing the gas-oil ratio at the vapor pressure. They will be reduced in a similar fashion. All of those figures there are based on 14.7 and may be corrected to 16.4, just as I have corrected the final deduction to that basis.

340 (EXHIBIT NO. 70 for identification, offered and received in evidence without objection.)

Cross-Examination Interposed by Mr. Slaff.

"Fluid level" on Exhibit 70 means that the oil rises up into the casing to a certain depth, depending on the pressure on the well. That fluid level is where the oil rises to in the casing above the bottom of the hole. "Ca." is an abbreviation for circa, meaning approximately.

Cross-Examination Interposed by Mr. Booth.

There was a special reason for selecting these particular four wells. As I said before, the samples were taken in a cooperative arrangement with the Phillips Petroleum Company. They were able to take those wells off production and prepare them for removing the samples, and they were in the area in which we were interested, so we took those wells.

Direct Examination Resumed by Mr. Morgan.

I had nothing to do with selecting these wells myself. The Phillips Petroleum Company selected them. We did not have any oil wells down there that we could test. We made an effort to get permission to take samples from other wells in the field; but these were the only wells we could get permission to use.

I have prepared curves which set out the same results as those pictured on Exhibit 70. I will put the adjusted quantities, measured on a base of 16.4 pounds per square inch, on these curves as I did on the other.

(Document entitled "Solubility Curves," marked Exhibit No. 71 for identification.)

This set of curves is set up in the same manner as Exhibit 69, showing the relationship between pressure and solubility of the gas in the oil. There are four curves shown here, representing the four different wells which we have discussed, marked curves Nos. 1, 2, 3 and 4. This curve which is shown as a broken line and marked "Calculated" was calculated from the analysis of the crude oil sample that was removed from Cockerell No. 41, showing, I think, extremely good agreement between the calculated values and the experimental data as illustrated by Curve No. 1.

(EXHIBIT NO. 71 for identification, offered and received in evidence without objection.)

As to how I account for the difference in the gas contained in solution in the bottom of Cockerell No. 41 and the other wells used in our tests, it looks as if the oil sample that was taken in each one of these wells had a different composition—contained different amounts of gas in solution. The test data shows that the oil was not saturated to the same extent in any of the samples taken. The oil in Cockerell No. 41 was the most highly saturated of the four samples. That is sample No. 1, on the curve, Curve No. 1.

As to the selection of the equipment to conduct these 341 tests, I repeat that this is a specialized piece of equipment, and there are comparatively few places where apparatus of this type is available. That apparatus was developed by Dr. D. L. Katz, who is now at the University of Michigan, I believe, and Mr. K. H. Hachmuth. The original design was made by them for some work which was published in Industrial and Engineering Chemistry, under the subject of "Vaporization Equilibrium Constants in a Crude Oil Natural Gas System," in September, 1937. This is the equipment which is described in that publication. That is the name of the article. It is published in Industrial and Engineering Chemistry, Volume 29, page 1072.

I might also add that a certain change has been made in the apparatus which we used, as shown on this diagram in the article just referred to. They used a stirring device consisting of an electric motor within this closed cylinder.

However, in this article to which I have just referred they had a vapor space above the oil so they could put their motor in the vapor space. In the samples that we ran here it was all oil in the cylinder. They could not put an electric motor in there, and for that reason we substituted this spring device which I described earlier. Otherwise, the apparatus is exactly the same. That equipment, which is owned by Phillips Petroleum Company, is, so far as I know, the best available equipment for conducting such a test.

As to what in my judgment occurs as oil is being raised from the bottom of a well by a pump or otherwise to the mouth of the well and produced with reference to whether or not it discharges all of the gas by the time it reaches the surface and is reduced to atmospheric pressure, I think it is very unlikely that all the gas could be discharged in the manner in which the oil is brought to the surface. There is a comparatively small amount of agitation. The oil is usually sent to a separator tank where there still is very little agitation, so I cannot see that you would get anywhere near all of the gas out of solution that you would normally expect to come out if it were in equilibrium with the oil.

As to whether the oils taken from those four different wells were saturated or under-saturated with gas, we found that Cockerell No. 41 was entirely saturated with gas at bottom hole temperature and pressure; and we found that the remaining three were under-saturated with gas.

Questions by the Examiner.

I do not know what the Railroad Commission's report shows the gas-oil ratio of these wells to be.

Cross-Examination by Mr. Slaff.

I have not testified in any other cases.

342 W. F. BRAINARD, a witness for defendants, testified as follows:

Direct Examination by Mr. Morgan.

(June 28, 1939.)

My name is W. F. Brainard. I live in Amarillo, Texas. I am a geologist for Texoma Natural Gas Company, working under Mr. Peterson.

I received my Bachelor of Science degree from Syracuse University in 1917, and my Master of Science degree from the same university in 1922.

Since the completion of my university courses, I have been employed almost entirely either with an oil company or with Texoma Natural Gas Company. My first employment was with the Empire Oil & Refining Company, at Bartlesville, Oklahoma, where I was employed as a geologist for a little more than thirteen years, beginning July 2, 1923. During that period I did my geological work in the north central division of Texas, with offices at Wichita Falls; and in the western division of Texas, with offices at San Angelo, Texas.

During those thirteen years I had occasion to do geological work in the Panhandle field. In the last two and a half months of 1924 and the first half of January, 1925, I made a sub-surface map of the Panhandle area from Potter County to the Oklahoma line. While I was with the Empire I do no other work in that field, except to keep up with it casually. For about three years after I went with the Empire we had charge of the Panhandle district from the Wichita Falls office. They did not create a district office in the Panhandle until 1926, and prior to that time the Panhandle district was handled out of our office at Wichita Falls.

I went with Texoma Natural Gas Company in November, 1936. Since that time my work for Texoma has been general geological work pertaining to the production of natural gas. I have worked in continuous association with and under the direction of Mr. Peterson.

I have had occasion to become acquainted with the geological situation in the Panhandle during the time I have been dealing with that field. I know the general formational conditions in the vicinity of the producing areas. I have been requested during the past three or four weeks to

prepare some cross sections or lineal sections through a portion of the field.

(Map entitled "Texas Panhandle", marked Exhibit No. 72 for identification.)

Exhibit 72, headed "Texas Panhandle," is now presented to me. The base map was prepared by Mr. Peterson, or under his direction. It was just a plain map without any of the other data which appears upon it now. The black and red lines and the broken lines on that map were placed there under my direction.

343 The heavy black line is the 1938 Railroad Commission of Texas production boundary.

The broken blue line through this area is the oil line of the Texas Railroad Commission.

The red line marked "AA" through this area is one of the lines of cross section shown on another map.

The "BB" line, also in red, and broken, is the line on a section marked "B" on another map.

The line "CC" is a third line of cross section.

The reason for the irregular course of each of those lines is that it is utterly impossible to make a section in any area through an oil field in a perfectly straight line. You have to zigzag back and forth for your control, because in many places where you would place control if you were putting it in a straight line there are no wells from which to obtain your information. Those lines run from well to well, and at each break in the line is a point at which our data were taken.

I tried to pick out an area in which I wanted a control point, and then went through the drillers' logs, and in many instances took the first one I found in that area to secure my data from; provided, of course, the information was complete on that one. Point "A" is just a mark on the line of cross section. The end of the line in Hutchinson County near which is the letter "A" is at a well, the log of which I had before me at the time I was doing this work. The end of that line is marked with the figure "1". In the case of the CC section you will notice each log is numbered, and the numbers of those logs there are also given on Exhibit 72 along this line at each point. This map is preliminary to some other drawings which will be hereafter discussed, and the line marked "CC" is the line which locates on the ground the wells set forth in the CC section of Exhibit 73.

(Document entitled "Cross Section, Oil Area, Texas Pan-

handle Field, Section C-C'', marked Exhibit No. 73 for identification. Document entitled "Cross Section, Oil Area, Texas Panhandle Field, Section B-B'', marked Exhibit No. 74 for identification. Document entitled "Cross Section, Oil Area, Texas Panhandle Field, Section A-A'', marked Exhibit No. 75 for Identification.)

Exhibit 74 is the section identified by the line on this map marked "BB".

The line "AA" on Exhibit 72 locates the wells used in making the cross section AA.

On Exhibits 73, 74, and 75, the wells at the northwest end of the three red lines C, B, and A, respectively, are located at the lefthand side. I have put the same numbers on Exhibit 72 at each break of those respective lines that are shown above the wells portrayed on Exhibits 73, 74, and 75, respectively.

344 Going back to Exhibit 72, I point out that the line CC is located toward the higher part of the structure to the southwest from the oil and gas contact line, as shown by the Railroad Commission, the line of section being the broken blue line. The line is located very close to the southwestern edge of the oil producing area.

Line BB zigzags back and forth across the oil and gas contact line as shown by the Railroad Commission, and is as near as it was possible to make it through the center of the oil producing area of the Panhandle field.

Line AA is between the oil-gas contact line as shown by the Railroad Commission and the side boundary of the field as shown by the Railroad Commission, and is located approximately at the outside edge of the producing oil area. The oil-gas line of the Railroad Commission does not extend as far east as my line AA. The point at which the Railroad Commission line stops is right here just south of Pampa, and I continue my line along the boundary of the field on over into western Wheeler County, approximately to the limit of the main productive area of oil for that field.

Exhibit 73 was prepared under my direction. I procure and assembled the data from which it was prepared. I used the data obtained from the drillers' logs of each of the wells shown thereon. There are 41 wells shown on that exhibit, and they are located, as I have already said, along the line CC, beginning in the northwest and moving southeasterly, on Exhibit 72.

On that exhibit I show some perpendicular double col-

umns, which represent the position of the well itself, just the lower part of the well, the upper part having been cut off because there was no necessity for showing the entire well from the surface down. The productive oil and gas horizons are the portion of the formations penetrated by these wells. There is no area or horizon productive of oil or gas in any of the wells shown on those logs above the portion which is set forth on the exhibit.

The horizontal lines running clear across the drawing and many of them crossing the lines which represent oil wells are explained as follows: The first line shown on this section is the sea level line and is so marked. Each one of the successive lines above that sea level line represents distances of 100 feet. For instance, the first line is 100 feet above sea level, the second 200, and so on.

I show each one of the producing formations or shows, either of gas, oil or water, in connection with each well represented on Exhibit 73.

There is some lettering at the top of each of those double columns. The number at the top corresponds to the number on Exhibit 72, which we have already discussed, and then below that is the name and location of the well itself. The lettering at the righthand side of each one of those columns as you come down toward the bottom represents
345 the point from the surface at which that particular show or pay was recorded in the log. A "show" would simply be perhaps a showing of oil or of gas, but which would not be productive in commercial terms, while by "pay" I mean where you would get sufficient amount of either gas or oil to be commercially productive.

Those figures are shown on the righthand side of each well. The figures at the left are the datum planes above or below sea level, whichever the case may be, of the show or pay which is recorded in the drillers' logs.

Across those double columns which represent wells there are some lines or bands, some of them colored in red and some in green and others in black. The red color represents gas horizons, either shows or pay horizons. The green represents either oil shows or oil pays; and the black represents water horizons.

Taking well No. 1, the log shows that at a plus 450 they had two million cubic feet of gas. From a plus 305 to a plus 293 they had three and a half million cubic feet of gas. From 132 to 120 plus, they had five barrels of oil per day and one and a half million cubic feet of gas. At plus

32 to plus 25 they encountered one bailer of water per hour, the total depth being plus 6, and the well was plugged back to plus 93. By plus I mean the distance above sea level. If a well is drilled below sea level, the figures after you cross the line of sea level would be designated as a minus.

In the third producing horizon, or the horizon which showed or produced both oil and gas, I account for the presence of both oil and gas in that horizon by the fact that it is very close to the contact of the oil and gas horizons. The relation between the oil and gas as it was found in that formation is that the gas was in all probability at the top of the oil. That is an ordinary thing to find down in that field, both oil and gas in the same producing formation, when you drill a well at the approximate location of the gas-oil contact line.

Questions by the Examiner.

The length of that contact line depends on the dip and the thickness of the pay. As to giving you some illustrative distance, I do not know if I could give you an actual footage without having the thickness of the pay and the dip at which the horizon is dipping. If your horizon happened to be flat, your line would be long; and if your horizon is steeply dipping, your line is consequently going to be short.

Direct Examination Resumed by Mr. Morgan.

In the area which is productive of oil the dip varies considerably. In some parts of it you will have rather a steep dip and in other places it will be fairly flat. Where the formation dip is flat, the oil-gas line across the formation from southwest to northeast would be longer. If it happened to be at a place where the producing formation dipped steeply, the line would consequently be shorter. In addition to the incline, another factor to be considered is the thickness of the pay.

346

Well No. 2 is located about four miles southeast of well No. 1. In this well at a plus 274 they had a show of gas. At a plus 209 to 194 they had a million gas and a show of oil. At 154 to 149 they had an increase in gas and a show of oil. At 79 to 69 they had an increase to eight barrels

of oil, and at minus 16 to a minus 24 encountered one bailer of water per hour. As to the significance in the Panhandle field of shows of oil such as were encountered in well No. 2, it is just a show and could not be classed as a productive horizon. Where the driller records a show of oil, it means that sometimes the bailer comes out with a streak of oil on it, and again when he dumps the bailer for a sample in a bucket they wash out a little show of oil on top—some little rainbow or some phenomenon such as that. That is what I mean by show.

Questions by the Examiner.

There are different types of conditions in the case of wells which would require plugging back in one case and not in another. Sometimes the volume of water would be a condition and sometimes the water might exhaust or decrease in such a way that it would not be necessary to plug back. Other times they just go back and produce it anyway. In that instance it is perhaps possible to plug back after the wells come into production if the conditions should require it. If they shot the well and had a big shot hole, they might have difficulty in plugging off the water. By that I mean if they applied nitroglycerine and blew out the bottom of the well bore so that it became enlarged. In that case there would be difficulty in plugging off the water. It would continue to come in around the plug.

The acidizing or shooting of a well is necessarily a bottom hole operation; but although it may be a bottom hole operation, they have means of placing their shot or their acid where they want it.

Direct Examination Resumed by Mr. Morgan.

Passing now to well No. 3 shown on that exhibit, at a plus 32[illegible] to 321 they had a show of gas. At a plus 266 to 256 they had an increase in gas. At 236 to 231 they had two million gas. At 163 they had a show of oil, and at 106 to plus 86 they had 300 feet of oil in the hole, and plus 81 was the total depth.

Questions by the Examiner.

As to why, if I show an increase of gas and beneath that a show of oil, the show of oil is a little wider than the increase of gas as represented by these bands, I point out

that that just happens to be a case of drafting. In other words, to get both of them in there, they sometimes make one a little wider than the other to show that they are both there. There is no relationship whatever between the width of these two bands.

Direct Examination Resumed by Mr. Morgan.

I now pass to well No. 4. At a plus 231 they had a 347 show of gas. At a plus 191, they had an increase in gas. At plus 161 to 124, they had a show of heavy oil; and from a plus 121 to a plus 91 they had a show of oil. Plus 37 was the total depth. I mean by a "show of heavy oil" a case where the driller's log records a show of oil which he does not figure to be a producing oil. It is heavy and sometimes when you get a piece of the rock out of that well it shows more or less like a tar formation in the rock itself. It is not considered a producing formation. There are two other terms used in the field which are synonymous with a "show of heavy oil," namely, "dead oil" and "black oil."

As to each of the others of the 41 wells, the figures and bands show for themselves what was encountered in each one of them. Where I show a formation which I describe as a pay formation, the thickness is drawn to scale. A little while ago when I was talking about the thickness of the bands having no significance, I meant only where a show is recorded at a certain given foot. That show may be in a very slight thickness.

Concerning the exhibit as a whole, there is no instance shown on that exhibit along line CC where a formation which was capable of producing oil was encountered above a formation which produced gas. Nineteen of those wells were drilled within ten feet of sea level. In five of them water was encountered. The water reflected in the drawing is only the water which was encountered in the drilling of the well and, therefore, some of them were plugged back. If water occurred in any of those wells at a subsequent date the logs would not show it.

There are some other symbols on that map which I have not yet explained. There is the symbol up here, the title of the section, "Cross Section, Oil Area, Texas Panhandle Field, Section C-C," and, of course, the legend showing the oil pay colored in green; the gas measure shows col-

ored in red; the line of cross section, northwest-southeast; vertical scale, one inch equals 100 feet, and the horizontal scale, two inches equal one mile. The term "P.D." means per day. "B.W.P.H." means bailer of water per hour. "O.I.H." means oil in the hole. "T.D." means total depth. "P.B." means plugged back. "Pr." means per. "Pr." followed by "H." means per hour.

In one or two instances it says "Spray five barrels." That means coming with the gas, spraying out as a spray per hour. It does not come as a flow; it is being driven out with the gas. With reference to well No. 8 I have a legend "Swab 300 barrels—7 hours." The well would not flow and it was necessary to go in with a swab and pull it out. A swab is a tool that they use to pull the oil out of the hole. It is fixed so that it goes down into the oil; it loads with oil, and they pull it on out. It is a sort of temporary pumping arrangement.

Exhibit 74 was prepared under my direction from the same kind of data used in the preparation of Exhibit 73. It is the same type of information on this section as that set out on the previous one. This one shows 56 wells, ranging in a northwest-southeasterly direction along BB.

The symbols, legends and drawings have the same
348 significance and meaning on this exhibit as on Exhibit 73. There is no instance along that line in any of those 56 wells in which free gas was encountered at a level below a formation which was productive of oil. Of those wells 31 were drilled approximately to sea level.

Questions by the Examiner.

The legend "Sm. show gas" just means a small show of gas. There is not much distinction between "small show" and "show." They are both pretty small. On well No. 11 where it says estimated 6,000,000 and test one, it means that the gas volume was estimated by the driller to be approximately six million but when they came to test the well it tested only 1,100,000. In other words, his estimate was considerably high. The line across the "M" indicates million. As to the significance of the term "Oil in hole," the oil rises up that many feet in the hole from the bottom. If they have 300 feet of oil in the hole, the lower 300 feet of the hole is filled with oil. If they show an oil pay and the well is drilled deeper, the oil in the

hole probably increases, if they get an additional pay. The oil in the hole may be converted to show the barrels per hour by testing the well, or if their fluid rises so many feet each hour they know from the size of the pipe about how many barrels come into the hole. As to why well No. 22 shows 500 feet of oil in the hole instead of being converted into barrels, it probably was on the test, but they usually do not bother to test before completion of the well. In lots of cases they do not make tests then, but go on and complete the well and then make their Railroad Commission test.

Direct Examination Resumed by Mr. Morgan.

In an ordinary oil well when a productive formation is encountered, the oil comes into the well and rises in most instances to a certain level. That level has nothing at all to do with the quantity of oil that the well will ultimately produce. The rate at which it rises might have something to do with it; but the level is determined by the pressures prevailing around there.

Exhibit 75 was prepared under my direction from the same character of data as that used in the preparation of Exhibits 73 and 74. That exhibit corresponds as to location to the wells set forth along the red line marked "AA" on Exhibit 72, and the legends appearing on that exhibit are the same as those appearing on Exhibits 73 and 74. The drawings, symbols and lines have the same significance or meaning on this exhibit as on the two last mentioned.

39 wells are shown on Exhibit 75. In none of them was free gas encountered in productive quantities. There was no instance along that line where free gas was encountered below the highest formation which produced oil.

The logs along those lines do not represent all of the wells that were drilled along the general location of those three lines. I could have selected other logs or taken 349 logs of other wells drilled along the general location of those lines and constructed similar lines and similar cross sections. I am familiar with the logs of all the wells in that vicinity. I checked very nearly every one. Other groups of logs distributing wells along those three lines through the field would have presented the same general picture as they presented by the logs of wells shown on

Exhibits 73, 74 and 75. They would have varied only in minor details.

I don't know how many logs we have in our office; but I would say anywhere from three to five thousand. We have all the available logs of wells that have been drilled in the Panhandle, and I have studied those logs during my service there with Mr. Peterson. To my knowledge, there is no instance where any well has ever encountered free gas at a level lower than the top of the highest producing oil formation in the particular well. I do not know of any instance where free gas has been encountered in what has been referred to as the oil measures, that is, the part of the formations between the location of the oil-water line and the location of the gas-oil contact line.

Questions by the Examiner.

On wells 17, 26 and 30 there is a show of gas or some indication of the finding of gas. That is apparently just a small pocket. It does not give any thickness there. It just shows it at one particular point. It gives a thickness of ten feet on well 26. That would be an indication that there was a little gas on top of the oil in that ten feet. In well 30 there is a show of one foot. Geologically, I would account for the presence of that gas by saying it is just a little local condition.

Direct Examination by Mr. Morgan (Resumed).

The cross sections show at the top of each well the name of the owner of the well. At the top of each column is a number, which corresponds to the number on the line of cross section on Exhibit 72; then the name of the producing company, the name of the fee owner, then the footage, the location of the well from the section lines, then the section, block and survey and the county, and also the surface elevation at that point. The top name signifies the producing company or individual who owns the lease. The name right under that is the name of the fee owner on whose land the well was drilled and from whom the lease was taken.

(EXHIBITS NOS. 72, 73, 74 AND 75 for identification, offered and received in evidence without objection.)

Cross-Examination by Mr. Slaff.

I have testified one other time. I testified in a salt water suit for the Empire Oil & Refining Company. That was a suit for damages due to the pollution of a stream by salt water.

350 (EXHIBIT NO. 65 for identification, offered and received in evidence over the objection of counsel for the Federal Power Commission, to whom the Examiner granted an exception.

Document consisting of logs of wells shown on Exhibit No. 16, fourteen in all, furnished by defendants' witness Peterson at the Examiner's request, marked Exhibit No. 76 for identification. Counsel stated that Mr. Peterson had requested him to explain to the Examiner that Exhibit No. 16 represents Mr. Peterson's interpretation of these logs from the top of the Big Lime on down, and that above the Big Lime he did not pay so much attention to the details because he did not consider those formations material.

EXHIBIT NO. 76 for identification, offered and received in evidence without objection.)

351 FLOYD C. BROWN, a witness for defendants, testified as follows:

Direct Examination by Mr. Morgan.

(June 28, 1939.)

My name is Floyd C. Brown. I live in Chicago, and have lived there since July, 1931. I am Vice President and General Manager and a member of the Board of Directors of Natural Gas Pipeline Company of America and Texoma Natural Gas Company.

I received my educational training at Stanford University, in California, receiving an A.B. degree in civil engineering in 1912 and a Master's degree in 1913. I remained in the University as an instructor in the engineering department for two years.

Following the completion of my education and my experience as an instructor, I was continuously engaged in engineering and construction work from the time I left the University until 1917. During this time I was engaged

in field and office work, but it was largely construction work. I was employed by numerous companies: a subsidiary of the Great Western Power Company; Duryea & Gilman; Blakewell & Brown; Edward T. Foulkes; City of San Jose; Shell Oil Company; and during that time with contracting firms for short intervals.

In 1917 I accepted a position in Bartlesville, Oklahoma, as superintendent of construction with the Empire Companies. They were subsidiaries or affiliates of the Cities Service Company, of which Henry L. Doherty was the principal owner. In that capacity I supervised the design and the laying of oil and gas pipelines, the construction of oil refineries, gasoline plants, compressor stations, oil pump stations, and general engineering work in connection with field operations of the companies' oil and gas properties located in Texas, Oklahoma, Kansas, Missouri, Arkansas and Louisiana.

In 1919 I was advanced to the position of chief engineer, and supervised all of the engineering design and construction of the companies' mid-continent oil and gas operations. In 1920 I continued as chief engineer but was given additional responsibilities of managing and operating the companies' crude oil transportation system, and in that capacity I had charge of construction and operation of the companies' crude oil pipelines. I also handled the crude oil buying and selling, which involved supplying the companies' refineries. As I recall, the company had six refineries at that time. We also engaged in the purchase and sale of crude oil for outside companies, and handled some common carrier business through our pipelines for other concerns. I continued in that dual capacity until 1921, when I was made vice president and assistant general manager of the whole group of Empire Companies.

352 As vice president and assistant general manager of the Empire Companies, I still was concerned with the operations and the capital expenditures being made by the company, and also, as the title implies, had responsibilities of an executive nature, assisting the general manager in forming and carrying out the policies of the company. My duties comprehended both oil and gas operations.

The group of companies known as the Empire Companies were engaged in producing both oil and gas. Their activities were those that would be customary in the trade for integrated companies, and involved geological work, the taking of leases, the producing of oil and gas; then

tracing the oil through from the producing wells, its gathering, transportation, refining, and marketing, to the retail gasoline consumer, as well as handling the other derivatives, such as lubricating oil, fuel oil, wax, and the hydrocarbon products made from crude oil.

On the gas end it involved the same geological work, leasing, the producing of gas, its gathering and transportation to markets, not only wholesaling to company owned distributing companies, but also to other companies, and the operation of the retail distributing outlets to the ultimate consumer.

In the same way, the natural gasoline made from casinghead and dry gas was manufactured and either sold as natural gasoline to refiners, or refined in our refineries and sold as motor fuel.

I was not relieved of the position of vice president and assistant general manager of the Empire Companies until some time in May, 1930; but I was relieved of active responsibility in that connection in September, 1929, when I was called into New York in connection with the work of Natural Gas Pipeline Company and Texoma.

During the period prior to September, 1929, when I went to New York in connection with the two companies just mentioned, I had had occasion to learn about the Texas Panhandle gas field. Under the companies' geological and leasing activities we started at a very early date—I don't recall the exact date, but my first contact in an intimate way with the field that impresses itself upon my memory was about 1926, though we had leases and vast holdings in the field prior to that time; but the development, which was primarily an oil development, had not attracted a great deal of attention, at least so far as our company was concerned.

In 1926 we were impressed with the showing of gas that was constantly resulting in a widening of the field and the area which was known to be productive of gas. We were conscious at that time that there was a field of magnitude. We didn't know how much, but each time an oil well was drilled it seemed like it resulted in a gas well, and we could see the field spreading out. We knew that there was a field of magnitude there.

This field attracted the attention of Mr. Doherty.
353 He was very much interested in gas reserves and was anxious to try to see if it would not be possible to build a pipeline from the Texas Panhandle to the northeast,

with Chicago as a terminus. He even had in mind other markets and going farther east, but that was his principal objective at that time.

Mr. Doherty asked our engineering department in Bartlesville to undertake the geological determinations as to whether there were sufficient gas reserves to support such a pipeline; to assist the engineers of Henry L. Doherty & Company in New York in the making of market surveys, analyzing the potentialities of the markets and the price at which we might reasonably expect that natural gas could be sold in competition with coal and fuel oil in these markets; to estimate the cost of building such a pipeline and the cost of operating; and in general to analyze the economic feasibility of constructing such a line.

In pursuance of those instructions our engineering department undertook such a study. The entire problem of this study was more or less my assignment to carry through in an executive way, and in an engineering capacity to supervise this work and see that the study represented a cross section of the combined best judgment of our executive and engineering staffs. We arrived at a conclusion which we reported to Mr. Doherty. We reported adversely upon the building of a pipeline at that time, very much to Mr. Doherty's disappointment.

The adverse factors were based upon economic studies; but I think I could say that our conclusion was influenced most by our inability to obtain pipe which we deemed satisfactory for the building of a pipeline of this character, or a pipeline of the character that we felt we should have for undertaking such long distance transmission of natural gas.

Natural gas had never been transported distances of nine hundred to a thousand miles, and we recognized, or felt that we did, that we were confronted with a different set of economic conditions than that of transporting gas short distances, and the pipe was the main influencing factor in retarding our going forward at that time.

There were very many natural gas pipelines in operation at that time; but there was no pipe obtainable in a practical way outside of lap welded pipe. Lap welded pipe obtainable today is of a better type than that obtainable in 1926; but even today it is not pipe of a character that we would consider suitable for the building of a pipeline of this type. In 1926 the lap welded pipe then obtainable in commercial quantities was limited to 22 inches in

diameter and very short lengths. The length was a function of the method used in its manufacture, and the very method used limited the length to around 18 to 22 feet.

In laying a pipeline, the longer the joints of pipe are, the less will be the capital cost and the laying cost in connecting those joints in a pipeline. The actual cost of join-
354 ing two pieces of 24 inch pipe is quite a factor, so that was an item in determining the economic study at that time.

The lap welded pipe was only obtainable with thick walls, short lengths, small diameters and low tensile strength, and from the way in which it was made it was so lacking in uniformity that there was no dependable or reliable way of determining what the joint efficiency would be. As a result of that, we had to use such low operating pressures that we were unable to take advantage of the thick walls that had gone into this pipe. In other words, you could get very little carrying capacity out of a ton of steel, as compared with thin-walled pipe of higher tensile strength which could be rolled into larger diameters to give you a great deal more carrying capacity per ton of steel.

Questions by the Examiner.

By joint efficiency I referred to the strength of the lap weld in the pipe and the strength of the steel from which it is made. Perhaps I can best explain that by outlining the method of manufacture. Lap welded pipe starts in its manufacturing operations as a strip of steel, which I think we would call a plate but in the trade it is termed a skelp; and this skelp is cut to the desired width and length and rolled to the desired thickness. Then this first plate or skelp is passed into a heating furnace which in the trade is often termed a soaking pit, and brought up to a red heat. It is removed from the furnace and passes on to a moving table, where the flat plate passes through shaping rolls and is formed into a cylinder. During the same operation, simultaneously with the shaping of the skelp into a cylinder, the edges are beveled or scarfed. The cylindrically formed skelp is then passed again into a furnace and the two edges which have been scarfed and overlapped in forming this cylinder are reheated and brought to a welding heat. As the cylinder leaves this furnace it passes over a mandrel, which is a large cylindrical bar of steel. This mandrel supports or backs up the two scarfed edges which are being

welded together, on the inside. Passing on the outside are rolls which exert pressure upon the two edges, causing them to be fused together to form a welded joint.

Direct Examination Resumed by Mr. Morgan.

This would leave a seam along the full length of the cylinder, and that is the joint to which I referred when I was commenting on joint efficiency.

There was one feature of lap welded pipe which might be very objectionable for pipeline engineering, particularly if you wanted to work your steel to the highest possible stress. This was the fact that often when this pipe was brought out of the reheating furnace for the final welding operation, if there was any pause in the operation, the pipe was chilled, and the two scarfed edges might be stuck together and have every appearance of being a perfect weld, and yet upon testing you would find that this pipe was only stuck together on the two edges. You never could be sure of the safe working pressure.

There is another matter which I think might be of
355 further interest. The question arises in anyone's mind:

Why couldn't you test this pipe? We did test it, even though it was factory tested above the working pressure at which we expected to use it in the field. Upon completion of the line in the field the line was again tested, and frequently we had many, many joints of this pipe let go or fail in the lap weld. It was common practice to test our lines in oil field work well above the pressures at which we expected to operate, and so after the line was completed we tested it with water.

After the line had been tested and the breaks successfully repaired, we found that this line often would fail, or joints would fail, at pressures materially below that at which it stood a test, when these joints did not fail. This phenomenon we could not explain, and we are not able to explain it today. It may be due to oil being practically incompressible, due to what we term a hammer, corresponding to what we term a water hammer or impulse as the reciprocating pump might throw a surge against the line, and incidentally cause higher internal pressure than the static pressure that was created in testing it with water. But that was a condition that confronted us in the use of this pipe.

Similar difficulties have been encountered with this lap welded pipe in the operation of gas pipelines for short distances and after the line had been tested; but we had this condition, we could not set a factor of safety upon which to design without going way below the normal stress at which the steel should be worked.

There are other factors in this lap welded pipe which influenced our judgment materially at that time. Lap welded pipe was seldom, if ever, uniform in its wall thickness. It was not concentric, it was not round; and the tolerance or the variations in the external diameter measurements were so irregular as to cause extreme difficulty in the welding of the two joints end to end, field welding. Then if the line was to be coupled with what was termed a steel and rubber coupling—there are various types of coupling on the market but they all rely upon a rubber gasket for sealing the pipe and giving you tightness against leakage—as a result of the wide variation in the external diameter, or lack of tolerance as it is termed in the trade, it was necessary to purchase couplings sufficiently large to receive the largest of these joints of pipe through lack of any external diameter uniformity. The result was that the other pipe being joined, being of smaller diameter, would rattle around in the coupling, leaving an excessive strain upon the rubber gasket, which was apt to blow out and give excessive leakage.

This pipe had been used for shorter lines. Under my direction, we built for the Empire a line from the Panhandle field to Wichita, Kansas, in the latter part of 1927. We built a 20 inch pipeline out of the Amarillo field and constructed it out of this pipe, and it gave us plenty of trouble, with the various difficulties I have outlined.

Back in 1926 and during that period up to 1929 there was no accepted standard of pressure ordinarily used by pipelines in transporting gas. It depended upon local conditions and the needs of the people constructing the line; but I would say that the pressures varied
356 from 150 to 300. There might have been lines operating at 350, but I don't recall any at this time. 300 was about the top pressure.

In 1926, when we were making this study, it was our view that it would be necessary to transport the gas at higher pressures over such distances as from the Pan-

handle field to Chicago. That was really fundamental in our unwillingness to accept lap welded pipe. We felt that to transport gas a distance of 950 miles, and to meet the competition to which we knew we would be subjected, would of necessity carry us into higher pressures than had ever theretofore been used. We felt that it was an economic necessity. We simply could not build the pipeline under the old customary practices, and it was necessary for us to deviate and get out into a field practically unexplored if we were to build a pipeline from the Texas Panhandle to Chicago.

In 1926 the prices of pipe fluctuated, but at that time the market price on lap welded pipe was in excess of $100 per ton. The fact that the walls of this lap welded pipe were very thick entered into the construction of the pipeline at prices of that character for distances of 900 to 1000 miles. The thickness of the pipe was naturally a function of the carrying capacity in thousands of cubic feet per ton of steel. In other words, if the thick-walled pipe of the smaller diameter was so constructed and of such a character that it was not possible or practical to make use of those thick walls in stressing the steel somewhere near its elastic limit, then obviously the cost of transporting a thousand cubic feet of gas would be influenced by the wall thickness and the price per ton of steel. That was a very important problem in this economic study. We could see that in a study of this problem we had to get the greatest possible amount of gas through pipe constructed from a ton of steel if we were to reduce our fixed charges, our overhead charges, to a minimum, and inject transportation economies into this project in a way that pipelines had never theretofore been designed, constructed or operated.

The character of fuel competition in the Chicago area, our principal objective, had a great deal to do with the economics confronting us. We felt that our market studies fairly well disclosed the potential possibilities of the markets and the competitive prices at which natural gas would have to be sold. But here we were coming in and invading a market served by other fuels. Natural gas was not available in the Chicago area. The fuel requirements of these markets were being served, and well served, by coal from local fields and fuel oil transported by pipeline from nearby fields in adjoining states,

and that fuel oil was seeking its market or its outlet in these markets. And coal from local fields was being marketed here. It was that sort of competition that we had to be able to meet, and that of necessity materially affected the economics and the feasibility of building a pipeline from this distant gas field.

Therefore, the character of the pipe which was then available in the dimensions we required, the cost of that pipe, and the economic conditions involved in the competition which confronted us in the area where we hoped to market our gas all combined to prompt us to make
357 an adverse report to Mr. Doherty. Mr. Doherty accepted our judgment reluctantly, but not finally. I am not sure that he agreed with all our conclusions. I think perhaps he was a little more optimistic than we who had been concerned with the preparation of the figures.

He instructed us quite firmly and quite definitely to continue our studies of the gas reserves, the influence of oil and water upon gas as it was being produced, the character of the gas wells, and to satisfy ourselves as to our judgment that the reserves were dependable. He instructed us to continue our cooperative assistance with the New York engineers of Henry L. Doherty & Company in keeping abreast of market developments in the Chicago territory; and, above everything else, to establish and maintain contacts with the steel mills, with the thought that a better pipe could be constructed; that if a better pipe was to be constructed it would be only by the pressure exerted from the trade; and that so long as the trade was willing to accept the pipe then made, that was the type of pipe we would get.

Without speaking disparagingly of the steel mills, they were interested in selling tons of steel, for which they were obtaining a high price. They were not interested in nor receptive to our suggestion that the pipe be made of thin walls, higher carbon steel that would withstand higher stresses, or larger diameter, all of which would result in the sale of less tonnage. Now, that was natural, and I don't wish to be disparaging, because later we had excellent cooperation from the steel mills.

In response to those directions from Mr. Doherty, we did just what he asked us to do. We carried out those instructions. We continued our geological studies in the

field. We continued our engineering and economic studies. We worked with engineers in analyzing the potentialities of the markets. We continued our studies of the fluctuations, the changing conditions, in competitive fuels as we found them in the period which transpired between 1926 and 1930, when construction of this line developed. This was most fortunate, because it did give us an opportunity of learning a great deal more about engineering principles which we had belief in but knew little about in a practical way. Also we knew more about market conditions and more about the field, and were better prepared to go forward at that later date.

At the time I went to New York about September, 1929, for the purpose of devoting my entire time to these projects, there had been quite a little change in the situation with reference to the price of pipe and the character of the available pipe. Part of this I am sure was the result of the competitive situation in the steel mills. The A. O. Smith Corporation of Milwaukee had developed an arc welded plate pipe, which was obtainable in 1929, and pipe could then be obtained as a result of that development by Smith in thin walls, large diameters—even up to 26 inch, and longer lengths. The price had dropped from $100 and over to $70 or $75 per ton, as I recall, in 1929 and the early part of 1930.

There was a difference in the knowledge which we
358 had in 1929 as compared with 1926 as to the extent of the gas reserves in the Texas Panhandle. This resulted from continuous development from 1926 to 1929. We had a great deal more information at that later date.

When in 1926 Mr. Doherty caused the first study and report to be made, there was no thought but that it would be a Cities Service project, or a Doherty project. He contemplated the undertaking of the building of a line as his own company's enterprise. That circumstance entered into the adverse recommendation which we made back in 1926. We felt that even though the pipe conditions had been different, it was a hazardous undertaking and an enterprise of such magnitude, with so many factors unknown and undeveloped, in transporting gas 950 miles into these competitive markets, with the millions of dollars involved, that it was more of an undertaking and a more hazardous enterprise than any single company should undertake.

There had been a change in the attitude of Mr. Doherty on this point by the time he called me to New York in 1929. As a result of our intermittent conferences on this subject of a pipeline from the Panhandle to Chicago and our discussion of the economic points involved, Mr. Doherty concluded that when and as the pipeline was built, it would be best to spread the risk between a number of substantial, reliable and experienced companies. That decision was followed up and others were invited into the project by the time I went to New York in 1929. A number of companies were invited to participate, including Standard of New Jersey, and the Chicago utilities as a group, and by that statement I refer to Peoples Gas Light & Coke Company, Public Service Company of Northern Illinois, Western United Gas & Electric Company. They represented the group of utilities serving manufactured gas to the Chicago metropolitan district. I have mentioned two groups: Standard and the Chicago utilities. Others were invited, including the Texas Corporation, Phillips Petroleum Company, Skelly Oil Company, and Columbian Carbon Company.

There was a reason for asking each of these companies to participate. In the case of Standard, it was a strong company, experienced in natural gas production, transportation and distribution. Standard had a call upon the gas from the largest singly owned reserve in the Texas Panhandle field, which is commonly called the Canadian River gas reserve. We were extremely anxious to have this supply of gas back of our pipeline, and although there was a prior call upon this reserve, it nevertheless was of such extent and magnitude that with an option for certain quantities over and above the requirements of the other pipeline, it would represent a very substantial reserve supply behind our pipeline.

In the case of the Chicago utility companies, they had acquired from the Gulf Production Company vast reserves in the Texas Panhandle which we were anxious to obtain possession of, and they were the logical marketers of natural gas in the Chicago area. It was our feeling, since they had distributing systems serving the domestic consumers in this vast area and were in position quite logically to serve the industrial consumers, that they were the logical ones to market an appreciable quantity of 359 the capacity of our pipeline. It was felt that as a

partner these utility companies would be more aggressive in the development of the markets, and that they would assist the owners of the pipeline company in more rapidly developing the load for the pipeline.

In the case of the Texas Corporation, Phillips Petroleum Company, Skelly Oil Company, and Columbian Carbon Company, we had a group of oil and gas companies experienced in the business—primarily as oil companies, but not lacking experience in gas—and who were the owners of very substantial gas reserves in the Texas Panhandle. These companies were all financially responsible and able to carry their part of the load, and they were looked upon as being eligible for participation in the project.

When I was called to New York to begin work on the project I was delegated the responsibility of representing the entire group. The group of participants had not at that time agreed that the project was feasible. They were awaiting the results of our studies, and by "our" studies I refer to the group of engineers whose activities I was supervising. There was seldom a day or a week or a month went by that new assumptions were not made, new factors imposed, and new conditions considered. This was such a sizable undertaking, with the engineering features so totally untried, that there was a great deal of time spent in discussing the soundness of our recommendations and as to whether we were safe in undertaking the building of a pipeline which might turn out to be an experimental failure.

The group reached the definite decision that they would go forward with the project about May, 1930. I had then been in New York about eight months.

I have heretofore referred to an improvement in the pipe situation, which I referred to as an improvement in the method of welding the seam, the thinning of the wall, and the adding of carbon content so as to make it practicable to produce a thin-wall pipe of large dimensions which was an improvement over the old lap weld pipe, which I described in some detail. I referred to the method of making arc welded pipe from plate as employed by the A. O. Smith Corporation of Milwaukee in 1929, which method was essentially as follows:

A plate of steel of the desired thickness, length and width, which could be shaped by pressing into a cylinder to form a piece of pipe of the desired diameter and length, was the first step in the operation. Prior to the forming of the plate into a cylinder, the edges were scarfed. This scarfing

was not a beveled scarf, but described as the quadrant of a circle, so that when the two edges of the plate were brought together they formed a semi-circular groove. It was into this groove that the foreign metal was deposited through electric welding.

That is essentially the whole operation; but I would like to explain that this represented a vast improvement over lap welded pipe because you could get the pipe to any desired thickness of wall and you could get lengths at that time up to 30 and 35 feet as against the old 360 18 and 22 feet of lap weld, and the joint efficiency which I have described in this arc welded plate pipe was vastly superior. By this I mean the longitudinal seam. It is that joint which forms the two edges of the plate into a pipe from the cylinder which was formed from the plate. This joint, however, while it was a vast improvement, was not homogeneous. It was the result of deposition of a foreign metal fused with the base metal of the plate, and it contained what we termed blow holes, gas pockets. There were slag inclusions and there was still some question as to whether the method of manufacturing resulted in producing a pipe the longitudinal joint of which could be relied upon to develop the strength of the steel, so the Smith Corporation set about to develop a new method of welding the two edges of the plate together.

We think that our engineers and myself had something to do with this new effort; but our work was that of expressing our dissatisfaction with the old pipe and expressing such knowledge as we had gained about electric welding and pipe from working with their engineers. I think maybe we had a little to do with it; but much credit is due that organization for the ingenuity and the diligent way in which they went about to solve this problem. I would not detract a bit from giving them full credit for the way in which it was developed, but we were keeping up with it step by step very closely.

The new method, very briefly described, was that the plate was still formed in much the same method, except that the two edges were left plain, sharp square edges. They were brought together in a press, leaving a gap of approximately 1/16 inch, and to each side of the gap was attached the electric current, and through electrical resistance the two edges were brought to a fusing heat. While in that molten state the presses were closed, or brought more closely together, forcing the two edges of the plate to form

what is termed in the trade a butt weld. This resulted in some of the molten metal being icicled, projected inside and some outside, but through a press and tooling arrangement these edges were squared up and the molten metal formed into a solid bead, which increased the thickness of the base metal at that point.

Attention should be drawn to the fact that we now had a piece of pipe formed from one piece of metal with no foreign welding rod included. We had a homogeneous piece of metal throughout its entire circumference. This pipe developed the characteristics we were seeking.

The development of that pipe resulted in further progress in the production of pipe suitable to an undertaking of this kind. Although our tests on the Smith pipe indicated that vast improvements had been made, we were still desirous of obtaining, if possible, a seamless steel pipe. A seamless steel pipe had been made by a number of the pipe manufacturers prior to 1929, but none had ever attempted to manufacture a 24 inch seamless pipe, or pipe as large in diameter as 24 inches, so we set about to try to accelerate and stimulate the interest of the steel companies in making a large diameter seamless pipe. That is a complicated process. They were not equipped with tools or
361 machinery to start the work, and some delay was experienced in getting them to work on the problem; but early in 1930 the National Tube Company, a subsidiary of the United States Steel Company, had equipped three of their plants to make 24 inch seamless pipe.

That was a very large undertaking. It was an expensive undertaking for that company; but I feel that they recognized as a result of the Smith competition that if they were to enjoy any further business on the big diameter pipelines they must of necessity at that time start immediate work in the building of plants to turn out this seamless pipe.

The process of development was slow. They were soon able to make a 24 inch seamless pipe, but it was thick walled and irregular in wall thickness. It was not uniform. They could not get long lengths, and the diameter tolerances were bad. About half of this pipeline, the Natural Gas Pipeline Company of America and Texoma's line, is constructed from National Tube seamless pipe, and the rejects by our inspectors of seamless pipe I would say would cover a ten acre tract at least ten feet high. I only express that to explain the diligent way in which the steel company worked

and the expense to which they were placed in trying to develop a satisfactory pipe; but they did accomplish it and they did finally turn out a very excellent seamless pipe.

As I say, about half of our line was constructed from that seamless pipe. I do not know the exact figure. The remainder was constructed from A. O. Smith pipe, so that in part of our line the seamless pipe was used and in the remainder the electrically welded plate pipe which had been developed by the A. O. Smith Corporation.

By May, 1930, we felt that this pipe had been developed to the point where we could see our way clear to go forward with the projection of this pipeline. At any rate, we were ready to go forward.

There were other engineering principles involved in the building and putting into operation of this line in addition to those I have mentioned in connection with the pipe. When we started to try to secure a better pipe, we felt that much could be gained by changing the metallurgical characteristics of the steel, and we sought to get a satisfactory pipe from a higher carbon steel. Both the plate welded pipe produced by Smith and the seamless pipe of which I have been talking have been developed as a thin wall pipe.

There was the problem, of course, of field bending in the laying of a pipeline over a rough terrain. This pipe has to be bent, and to bend a thin wall pipe of that large diameter is perhaps comparable to trying to bend a piece of stovepipe over your knee. Our job was to try to bend that pipe in such a way that it would not flatten, or, as we term it, become egg-shaped, so that we would not so collapse the pipe as to give it a point of weakness, sort of a hinge point for any contraction or expansion that might be absorbed in the pipeline at that point.

We had the difficulty of trying to weld high carbon 362 steel. The carbon content had not been changed essentially, but it was changed enough to throw out completely and make obsolete the electric and acetylene methods that had heretofore been used, so we started out with the electric welding people and the acetylene concerns to try to get what is termed a coated rod. It is a flux that is applied to the rod which helps to produce a more homogeneous and uniform weld. We made suggestions in developing that part of it, and we developed a maximum strength for the transverse joint in connecting two contiguous pieces of pipe in the field. We could satisfactorily weld that, but it lacked ductility. The welded joint was just as brittle as glass.

So that is only one of the difficulties that we had to try to overcome before we were able to start in a commercial way to lay this pipe that we had developed. We had the pipe but we were not sure we could get it in the ground and make it stay together.

There were other factors in developing the proper spacement of our compressor stations and as to whether we should employ the old compression ratios which had formerly been used, and we deviated materially from the former practice in the development of the design and the spacing of our compressor stations. This required special study in design and testing and experimentation to arrive at the proper spacing of our compressor stations. It was a part of our economic study to try to ascertain what intake pressures should be used to go with the discharge pressures.

I think I have failed to state that we had designed this line, or we were designing it, for an internal working pressure of 800 pounds, whereas the former practice had probably not exceeded 300 or possibly 350, so if we were to operate our compressor stations at 800 pounds, we again found ourselves in a new field.

The large compressor manufacturers had developed a 1250 horsepower engine, capable of meeting our requirements, but the compressors had not been developed, and this took us into a new stage of development to make available suitable compressors, and that involved considerable work in replacing the castings which, for the most part, had been of cast iron and now had to be of cast steel. The bearings all had to be lengthened and redesigned to get the proper bearings for those pressures.

The compression ratio I started to discuss might be termed the relationship of the absolute discharge pressure to the absolute intake pressure. By discharge pressure I refer to the pressure at which the gas leaves one station in its path of travel toward the next station in the direction of the markets, and the pressure at which the gas is received at that next station is termed the intake pressure. The relationship of the discharge to the intake pressure is termed compression ratio. The compression ratio formerly used had been in the neighborhood of three to one; that is, dealing in absolute pressures, it would go out from one compressor station at three times as high a pressure as it would reach the other compressor station.

It was our conviction, as a result of our economic
363 studies, that this compression ratio should be reduced to approximately one and a half to one. There is nothing sacred about a compression ratio of one and a half to one. That merely represented, under the conditions which we had imposed regarding the quantity of gas we sought to deliver and the size of pipe that was available, the pressures at which we expected to work throughout the distance it was being transported. That represented in our judgment the most economical compression ratio, to hold to a minimum the capital expenditures in pipe and compressor stations and still accomplish the maximum carrying capacity.

There were other engineering and physical problems involved in the transportation of gas at high pressure which were not encountered in the ordinary natural gas pipelines at that time. We had a problem which was accentuated by high pressures, but which nevertheless was present at lower pressures. That was the formation of gas hydrates. As Mr. Hammerschmidt explained yesterday, the formation of gas hydrates is a function of the temperature and pressure. Hydrates had formed in these old pipelines carrying moist gas at pressures of from 150 to 300 pounds. In the Mid-Continent field, in my own experience with the Cities Service Gas Company, which was one of the Empire group I spoke of, we had the experience of having these lines actually plugged, completely shutting off the flow of gas. On the removal of the pipe joints which were plugged, we found this ice formation, which to me resembles dry ice. It has a good deal of the same characteristics, such as smoking and fuming when it is released to atmospheric pressure.

We found those lines completely plugged. We recognized that there was something different about it than plain ice, but we did not know exactly its cause. All we knew was the effect, and that was very damaging. We knew that it had occurred in the presence of moisture. We had also determined that there was a relationship of pressure, but we did not understand the problem. We did not understand it, although we were working on it, when we built the pipeline. However, we knew that we were dealing with a gas saturated with moisture as it left the wells, and at the elevated pressures at which we expected to work we were going to have this freezing problem, so we set about to develop a dehydration plant for removing

moisture. This was described briefly yesterday by Mr. Hammerschmidt.

It worked quite effectively in removing this moisture and we had no trouble in the pipeline while it was operating; but much to our surprise, these gas hydrates started forming in the refrigeration plant because it was working at elevated pressures, about 730 or 735 pounds. So our problem was transferred from the pipeline into the refrigeration plant, and we had to do considerable work in improving the type of our refrigeration plant to overcome that difficulty.

In the meantime Mr. Hammerschmidt's research work was accelerated in trying to understand this hydrate problem better. It was largely the result of his efforts that the problem was solved. We have had some hydrate problems with the line since the dehydration plant was perfected and placed in use; but in one case it was the result of our
364 not completely understanding the problem. In an effort to economize, we shut down the dehydration plant one summer. We felt that during the warm temperatures we could operate this pipeline satisfactorily without the dehydration plant, and we shut it down. But when winter came we found that during the summer enough moisture had accumulated in the pipeline because of that shutdown to give us considerable difficulty, and it did give us considerable difficulty; so we have been using the dehydration plant since that time as an all year round operation, one which cannot be neglected for even a month at any time.

We have had hydrate trouble as a result of water getting into the lines through breaks. As I recall it, it was in February of last year that we had a failure of our pipeline. By failure I mean the line parted, pulled apart in one of these couplings. I have failed to tell you that the pipeline is constructed with alternate welded and coupled joints. But in one of these places where the two double joints were connected together with a rubber gasketed steel coupling, the water table rose until the ground was saturated to the surface, causing the pipe to float up and to pull apart. In getting the line back into place, some of this surface water, which we had attempted to blow out by blowing the pipeline from both directions, was left in the sags or low places, to which it had traveled down the pipeline, and this caused us a great deal of difficulty. It was a period of over two weeks before we were able completely to resume full time service.

I have described in some detail the pains to which we went in developing or recommending to the manufacturers the development of a pipe that was suitable, and the different types of machinery, such as compressors, engines and things of that sort which were suitable to our operations. We then took steps to see to it that the pipeline was constructed with the kind of pipe and equipped with the kind of machinery, such as engines, compressors, etc., that we had determined would be suitable. To start with, we realized that we were imposing upon this pipeline through these engineering features more rigid and severe conditions than had ever been imposed before, so we tried to make doubly sure that we were on safe ground, and therefore we wrote the most rigid specifications of which we were capable.

We prepared unusually careful detailed drawings—that is, much more care was exercised than we had ever used in any of our former pipeline experience or practice; and in the making or the manufacture of this material, whether it be pipe, compressor cylinders, valves, fittings, or assembled manifolds, or whatever it might be, we placed our inspectors in the factories and in the shops to see that the proper material, the material as specified, and the workmanship that was designated went into these facilities. After the material was manufactured, made or assembled, we used extreme care in factory testing before the material ever left the factory or was loaded on the cars.

I case of pipe, although we had watched the manufacturer in the development of the pipe, we still recognized that this one thing, above all else, had to stand the 365 test; so we selected at random approximately one joint out of very hundred that was manufactured—and by joint I mean a full length commercial piece of pipe approximately 40 feet long, 24 inches in diameter, with the same characteristics as embodied in the same pipe that we expected to place in the ground. These specimens, selected at random, were hydrostatically tested. We carried this test by progressive steps, raising the pressure from zero on up through the yield point, or the elastic limit of the steel, to the point of failure; watching and determining the characteristics of all parts of the pipe. We were anxious to see whether or not the points of failure were uniform, whether the pipe was going to develop a weakness in the joint or contiguous to it, as a result of the heat from

electric welding in the case of the Smith pipe. We wanted to try to determine whether the defects were of such uniform characteristics that we could ascertain safely what factor of safety or what margin of safety we could work to without the risk of having weak joints show up which would cause expensive failures.

This same practice was followed in testing the seamless pipe supplied by the National Tube Company. In National seamless pipe we did not have a longitudinal joint. Seamless, as the same implies, carries no joints or seams; it is just one continuous piece of steel. In the method of manufacturing seamless pipe they start with a solid piece of steel, termed a billet; and if there should be any irregularities upon the surface of this billet, they had to be carefully removed or they might show up in the piece of finished pipe in what we term cold seams or what might be termed cold laps or imperfections, which would extend from the surface halfway through the pipe, or clear through. We were equally anxious to determine the uniformity of the quality of the seamless pipe, and to check our design and make sure that we were on the side of safety.

In addition to the bursting tests, as these were termed, we also tested every joint of pipe before it was laid to a hydrostatic pressure of 800 pounds in the mill. That method of testing pipe naturally resulted in the rejection of some of the pipe. I described or attempted to tell you briefly this morning of the rejection of seamless pipe; and even after operations had been perfected to the point where they were in commercial production, we found it necessary to reject a great deal of pipe. On the Smith welded pipe their operation was a little more uniform in character, but we had heavy rejects of that pipe.

We made the same careful inspection and carried out the same careful tests on the other equipment, such as compressors, etc. We found it necessary to reject many cast steel castings which were employed in the fabrication of the compressors. The cast steel heads often came from the foundries in a porous nature, with sand inclusion or blow holes, and we arranged to test those to destruction to ascertain their qualities.

In the same way we tested the valves and fittings. We tested our couplings too. The 24 inch couplings were then being made, as had been designed, 24 inches in diameter to withstand these pressures. Every step that we

made took us into a new unexplored field, and we tested
366 the materials to an extent that they had never been tested before. That was the thing that bothered us from the beginning. We were not afraid of our theory or our engineering principles. We were sure of them; but we were not sure how this line was going to act.

To reassure ourselves on this point, in addition to the physical tests which were conducted, we laid ten miles of experimental lines; and this was, as I have already indicated, primarily to familiarize ourselves with the technique of welding transverse joints of high carbon steel. We felt that we could weld it better by cutting coupons from the pipe and developing a joint efficiency on that line, but the joints were so brittle and lacking in ductility that they would break as we tried to lower the pipe in the trench. That was one of our problems. It is fortunate that we did this experimental work because even though by the other tests the joints seemed to have the proper strength, they would not stand the expansion and contraction to which a line of this size would be subjected; but those problems were rather materially solved at the end of that experimental work. We felt we were at least better prepared to go ahead with our pipeline work.

I think we laid our first pipe along in August, 1930. Of course, there was a lot of preliminary work necessary, even after the final decision had been reached to go forward.

We then had to determine, when we finally decided upon the project, how it was going to be built, what we were going to do to get out the drawings, write specifications and place our bids. Practically every dollar of material that went into the pipeline represented competitive bidding for that material and the laying of the line, so there was a long period—I say long, but it was comparatively short considering the magnitude of the undertaking—between the time we decided to go forward and the time we actually got to laying the pipe, of probably three months.

In the meantime we had encountered the problem of where to lay our line, after it was decided what kind of line to lay. Although we had been working on that problem concurrently with others, we were considerably puzzled as to the best route for a pipeline from the Panhandle to Chicago. We were familiar with the area traversed from the Panhandle to Wichita, having laid that line for the Cities Service Gas Company in 1927, and we knew that

territory fairly well. By saying fairly well, I mean we knew the territory rather intimately, the soil conditions, topography, the nature of the streams to be crossed. But from the mid-point we were in doubt, and it was from there on where we experienced the greatest difficulties in finding a suitable location for a pipeline. It was not just as feasible to lay it in one place as another between the Panhandle and Chicago. We would have liked to have for the minimizing of the length, and economizing on the length of the line, the opportunity to lay a straight line from the Panhandle to Chicago; but it was not difficult to determine that such a location was impractical, because it would carry us through the flint hills of Missouri and the flood valleys of the Illinois and Mississippi Rivers, and though those two obstacles were not insurmountable,
367 we deemed such a route decidedly impractical.

The hills, termed the flint hills of Missouri, across which we would have had to lay our pipe had we followed a straight line, have outcroppings of limestone coming to the surface. It would have meant that the pipeline trench would have had to be shot or dynamited for long distances. I would not attempt to say how long, but it would be in excess of 100 miles. This pipeline trench had a minimum depth of five feet and a minimum width of 32 inches. At many places, because of the topography, to minimize sags and over-bends in the line, the pipeline trench was excavated twelve to fifteen feet deep. Obviously, if it is in rock, or if there is a caving formation, the trench is correspondingly wider at the top. That impressed us as being an obstacle of no small moment.

Looking further to the north and east we encountered these flood valleys of the Mississippi and Illinois Rivers, and from our search of government records we found that those valleys are not infrequently flooded for a period of thirty to sixty days, and it was across these flood valleys that it would have been necessary for us to lay our pipe if we had followed a straight line routing. Had a failure occurred through those flood valleys at a time when the water was high, it might have been 60 to 90 days before we could have resumed service; so we were impressed with the necessity of avoiding those physical conditions. We were then led to try to find a location to the north.

There was another difficulty along the straight route from the Panhandle to Chicago in addition to these flint hills and flood valleys, and that was in the use of crossings

under the Missouri River. When I was with the Cities Service Gas Company we had tried to cross the Missouri River north of Kansas City to serve our market at St. Joe, Missouri. The Missouri River is a treacherous stream at that point. It is subject to channel change, shifting of the channel; and the river at times, following thaws in the springtime, is subject to heavy scouring from ice gorges coming down the river, and twice we lost our river line across the Missouri River serving St. Joe.

Questions by the Examiner.

I probably did not make my statement clear. The city of St. Joe was served by the Cities Service Pipeline Company, and the experience I was reciting was during the time I was with the Empire and Cities Service Company in Bartlesville. That was off the line which was served by the pipeline from the Texas Panhandle to Wichita. When I said Wichita was the midway point, I meant it was approximately halfway the distance of the pipeline. As a matter of fact, it is a little less than half way.

Direct Examination Resumed by Mr. Morgan.

I was speaking of an experience I had had myself before we entered upon this project, and that is one reason I didn't want to put another major pipeline across the river at that point. They were finally able to work out of that difficulty by getting permission to put the line across a highway bridge. For the Natural Gas Pipeline Company we started looking for a crossing or a routing farther north.

368 We determined that the Missouri and Mississippi Rivers were such important streams that first of all we would have to determine the points where suitable crossings could be made with the pipeline. Those would become control points. In doing this work we used airplane and land reconnaissance work, and we made use of the government records, trying to study channel changes, high water records, and other factors which would assist us in determining the constancy of the stream, and whether some point which looked attractive at that time had maintained such characteristics in the past as to justify us in considering it a satisfactory crossing for the future.

Those studies revealed two suitable points on the Missouri River; one at Plattsmouth, just below Omaha, a distance, I should judge, of thirty miles, which would not be far off; and another north of Plattsmouth at a point called Rulo. That more southerly routing or crossing at Plattsmouth seemed to meet our requirements and was temporarily accepted.

We started then to make similar studies of the Mississippi River, and found what we considered a satisfactory crossing at a point known as Muscatine, which is south and a little west of the Tri-Cities, Davenport, Rock Island and Moline. Those two crossings then came to be the control points from which to work.

We started from the Panhandle field working towards Plattsmouth, and were assisted in the route from mile to mile through the aid of aerial surveys. We made aerial maps of a three-mile strip, which was the result of a paper location and field reconnaissance. Having made this preliminary ground location, we then, flying at ten thousand feet, photographed a three-mile strip; and with the aid of features developed by the aerial photography people, which brings into relief the topography of the country and the streams, etc., we were able to make a very satisfactory paper location, and we were able to project long distances ahead so as to miss cemeteries, churches, small municipalities, farm buildings, and so forth. By a three-mile strip I mean a strip three miles wide along the entire course of the pipeline.

(Map entitled "Relief Map Showing a Portion of Central United States", marked Exhibit No. 77 for identification.)

Exhibit 77 is a relief map, which I have caused to be prepared, showing the nature of the streams and waterways traversed by the pipeline originating in the Texas Panhandle and terminating at Joliet, Illinois. It shows the location of those streams and the names of some of them. The rather heavy reddish line going from a point in the southwest, or the lower left-hand corner of the map, in the Texas Panhandle, in a northeasterly direction and then in a general easterly direction over to a point near Chicago represents the route followed by the pipeline of Texoma Natural Gas Company and Natural Gas Pipeline Company of America from the Panhandle to Joliet.

Across the northwest portion of Missouri are flint hills in limestone. The State of Missouri is bounded on the

west by the Missouri River, and the point between Kansas City and St. Joe represents that point along the Missouri River across which a pipeline would have to be
369 placed if it were laid in a straight line from the Panhandle field of Texas to Joliet. It is in the northwestern part of Missouri, in the area which would be traversed by a straight line between Fritch, Texas, and Joliet, Illinois.

The flood valleys of which I spoke can best be visualized by the color legend on this map. This zone in yellow represents elevations from sea level to five hundred feet, and the color contiguous to that is five hundred to a thousand feet. The Mississippi River flood valley covers the portion indicated and this area shown in yellow. In the same way along the Illinois River there are times of the year during which much of that area shown is under water. We would have encountered the flood valleys of both of those streams had we gone in a straight line.

There are thirty-one streams of the magnitude that designates them as rivers between Fritch, Texas, and Joliet, Illinois. Some of them are called creeks, but they are more dangerous and hazardous from the point of view of pipeline crossings than others which bear the name of river. Some of the worst streams we cross are practically dry during periods of drought and are raging torrents during the flood season.

When I say thirty-one rivers, I mean that there are thirty-one rivers along the line as actually located. If we had gone in a straight line we would have encountered more rivers and they would have presented more difficult engineering problems. It will be noted that the route of this line carries us back nearer the head waters of these various streams, which converge down in this area I am indicating across which a straight line would have carried us. Also, as noted by the colored area on the map, we are back on higher ground, less subject to overflow. These streams are smaller and nearer the head waters than we would have had to cross using the straight line routing.

I have mentioned the engineering advantages of routing our line as we finally routed it. From the standpoint of capital expenditures, consideration of the type of construction, and the conditions which would be encountered, we were led to believe that a more circuitous route did not represent any greater capital expenditure than a straight line routing. We were further convinced that there would

be less interruption of service and lower maintenance and operating expense by getting back on high ground and out of these river valleys and following the routing as shown by the red line on this exhibit.

(EXHIBIT NO. 77 for identification, offered and received in evidence without objection.)

In speaking of our studies to determine the most practical and economical routing of our pipeline from the Panhandle field to Joliet, I spoke about familiarity with that area from the Panhandle field to Wichita, a point to which we constructed a pipeline for the Cities Service Gas Company in 1927, and termed Wichita as about the midway point. Obviously, that is confusing as a midway point because I did not state it as a midway point between what stations. It is about a midway point between the field and Kansas City, which was our destination at the time we were building the line for the Cities Service Gas Company; and it is that area from the Texas Panhandle to Kansas City with which
370 we were in 1929 most familiar. That area is across Kansas, Oklahoma and Texas, representing an area across which we had laid oil lines and gas lines, and had gas and oil operations, so that we were familiar with the streams and the soil conditions and the general topography from the Panhandle field through Wichita to Kansas City. Kansas City, in terms of the Chicago pipeline, represents approximately the halfway point between the Panhandle field and Chicago; and Wichita is approximately the halfway point between the Panhandle field and Kansas City.

I have told about the preliminary surveys, studies, experiments and tests, etc., in order to get the right kind of pipe and the right kind of machinery and equipment of different kinds, and of the pains to which we went in determining just where we thought it desirable to lay this line. Having done all that, there was the other troublesome step of procuring an easement or right of way from the land owners along the routing we had determined to be the one best suited for our purpose.

I would hesitate to say how many land owners we encountered along that route; but I will make a guess at it and say probably between 2500 and 3000. It was not just a matter of getting to these land owners. In the first place, the land owner does not look with favor upon a pipeline 24 inches in diameter coming across his land and digging a trench from five to ten or twelve feet deep, and the aspect

of the surface soil being disturbed, and a barren strip across his land resulting from the construction of a pipeline; and that is usually about what happens, in spite of our conscientious efforts to replace the top soil. It takes a number of years for that area to become again productive.

These farmers on the south end of that line have seen pipelines built and they know the effect it has upon the land. That is not true to the same degree on the north end of the line, but there are even greater difficulties encountered on the north end of the line which I will describe very briefly in a moment.

On the south end the farmers were antagonistic to a pipeline crossing their farmlands. It means that when that easement is granted there always must be granted the right of ingress and egress for the maintenance and repair of the pipelines, and that means that the trucks of the company must frequently be driven upon their land and across their crops, regardless of the state or growing condition of the crops, and that the company's pipeline walkers must patrol this line at least once a week and parts of it daily. So they do not look with favor upon the granting of a pipeline easement.

We found that the farmers in many communities had banded together, and it was just next to impossible to find a way through or around them. In many instances we resorted to options. We optioned as many as three lines. We found that we could make a certain distance in a troublesome area and we would get up to a dead end alley, so to speak, and we could not get any farther. We couldn't get around or through, and we would have to back out and start another line or another route around this troublesome area.

371 We also had the problem of starting the pipeline in advance of having obtained the easements throughout its entire length, with the hope that if there were any difficulties we could get them straightened out before we got to that point and that they would be cleaned up and time would cure them; but it did not always work out that way. We had some troublesome times getting our pipeline route worked out so as to follow as nearly as possible the paper location of the route we had selected.

On the north end of the line we encountered a more difficult problem, and that was that most of the land from the Missouri River east is drained with tile. This is a method

the farmers use and speak of as preventing their soil from getting sour or waterlogged. It seems there is an impervious strata a short distance below the surface which the water cannot seep off or through; and the water seeps to that point and soaks the land; so the land is all drained with this tile.

Our pipeline was buried at such a depth that it cut right across these tile drains, and to build this pipeline it was a job for the company to replace those drains and for a time thereafter to take care of them satisfactorily for the farmers and to protect them from the company's failure properly to install and relocate the drains, all of which, of course, was written into the easements.

That, in brief, is the right of way problem, but does not begin to explain the right of way difficulties we encountered. Farm organizations leagued together to prevent the building of the pipeline. There was always difficulty getting across railroads. Railroads do not look with favor upon the building of a pipeline in this area, which might mean the replacement of coal and affect their freight revenues from coal. Those are part of the right of way problems, the difficulties in obtaining easements upon which to build a pipeline.

In the course of that 950 miles we crossed a great many public roads. In getting permission to take our line along or across public roads we had to deal, of course, with the county commissioners and state highway commissioners; and in crossing all streams which are termed navigable streams we had to obtain permits from the War Department.

The first physical work in the laying of the pipeline was August 2, 1930, and the first pipe was actually laid August 22, 1930. As to whether the line was constructed by our organization under my supervision or let out by contract, it was a combination of those conditions. The physical work for the most part was performed by contractors. We contracted with them for the labor of actually laying the line. The company, through its mass purchasing power, purchased material and supplied it to the contractors, the contractors furnishing the labor, machinery and equipment with which to do the work. I couldn't say how many contracting firms we dealt directly with in the laying of that pipeline and in the construction of the compressor stations and other plant equipment. We dealt with many. Every

bit of work was let upon specifications and drawing
372 under competitive bidding. It is my recollection that the laying of the pipeline resulted in our employing five different contracting firms, and there were many other firms employed by those contractors in sub letting a part of the work. In some instances the main contractor would sublet the hauling to some teaming contractor equipped with trucks, tractors and equipment for getting the material on the ground. In other cases the main contractor might sublet the welding of the pipe or he might sublet the painting of the pipe; so that in laying the pipeline proper there were many sub-contractors used in addition to the main contractors bidding upon the different schedules or sections of the line.

I perhaps could make more clear the point or the method in which the work was contracted by saying that we divided the line into sections every 80 to 100 miles. That, we felt, represented a unit of work which a contractor could properly supervise, and if provided with the right kind of an organization and machinery that he could handle 100 miles satisfactorily. We were trying to spread the work so as to take advantage of all the capable contractors with efficient organizations and good machinery in order to construct the line in a minimum length of time and get it into operation.

The stations were constructed in the same way. We contracted for the buildings, the steel, corrugated iron, and the erection of the machinery itself, and then contracted to labor contractors the work of erecting the buildings and installing the machinery. There were very heavy foundations involving a great deal of mass concrete under those 1250 horsepower gas-driven engine compressors, and these contractors at times would sublet the erection of steel, the buildings, or they might contract the excavation work for the foundations, sublet the contract for the concrete or sublet the work of erecting the machinery or doing the pipe work.

In the same way the company houses were contracted, the company purchasing the material which was used.

Questions by the Examiner.

We supplied the material for the stations in the same way. We tried to take advantage of our purchasing power in buying all the material and then to get the best possible

deal on labor by letting that through competitive bidding. Once we had entered into a contract with the contractor who was constructing our line sections, we had to make a good many alterations. We had to make more than a few; and we had provided in the contract for the payment of extras to the contractor if the changes which we initiated resulted in the contractor's being placed to additional expense, and that brings up one of the unpleasant features which we experienced in the construction of the work.

We had to deal with contractors who, in the first place, had organizations experienced in this kind of work. We had to select contractors who were financially responsible and had the type of machinery which was necessary to lay a pipeline of this large diameter.

373 It will perhaps better illustrate the type of machinery that is employed when we visualize that a joint of 24 inch pipe 40 feet long, of the thickness we were using, weighs in the neighborhood of two tons.

As I have tried to explain, the pipe was alternately welded and coupled, and the welding took place on the surface of the ground over the pipe trench in which it was to be lowered, so when the pipe was lowered into the trench some machinery had to deal with joints welded together weighing in the neighborhood of four tons each. Therefore, it took heavy machinery, and it took specially designed machinery, with booms, drag lines, caterpillars, especially equipped to do this type of work, and there were not many in the United States qualified and equipped at that time to build this sort of pipeline.

For that reason we divided the line up, as I have described, and then we set about trying to draw specifications and to provide detailed drawings which would leave no doubt as to the meeting of minds between the company and the contractors as to what was intended by the inspection we expected to impose upon those contractors when this pipeline was constructed. Nevertheless, these contractors had not had the experience of building pipelines which would be subjected to these high pressures or to the close inspection and the tolerances to which we felt it necessary to work, and in spite of our warning at the time the contractors were bidding upon the work, it was evident as the work progressed that our inspection was far more rigid than they had anticipated.

As a result, two of the contractors made claims for losses approaching $300,000 each, and one contractor actu-

ally sued us for a sum of money slightly in excess of a million dollars for extras which he claimed he had not anticipated at the time he was bidding on the pipeline. In this case, which actually went to trial in the Federal Court in Tulsa, Oklahoma, the judge directed a jury verdict in the company's favor and the claims were completely disallowed. In the other two cases settlements were made after this trial suit had been brought against the company and lost. Settlements were paid on these two claims for nominal sums, which, as I recall, were around thirty to sixty thousand dollars.

Direct Examination Resumed by Mr. Morgan.

There were special engineering problems involved from our standpoint and that of the contractor in getting this pipeline across these 31 streams between Fritch, Texas, and Joliet, Illinois. Every stream represented a separate problem. I do not think there are ever any two streams that are quite similar. Each one has to be separately studied and receive its own particular treatment best suited to the conditions found there.

In getting a pipeline across a river there are two generally accepted methods in use today. One is termed the overhead suspension bridge type of crossing and the other is the multiple line submerged crossing. There have been in a few instances tunnels actually driven under the river and the pipeline carried through a tunnel under the stream; but the two methods most generally used in oil and
374 gas pipeline construction are the overhead suspension bridge and the multiple submerged line.

(Photograph hearing the designation "No. 1", marked Exhibit No. 78 for identification.)

Exhibit 78 is now presented to me. That is a picture showing the assembly of two 18 inch diameter gas lines upon a suspension bridge across the Big Blue River in Moore County, Texas. That is a photograph of a part of our pipeline system. It is not visible or discernible from the exhibit, but the 24 inch pipeline has been through a valve header reduced to two 18 inch lines. These two 18 inch lines are used for safety, ease and convenience in crossing the river on the bridge. At the other side of the river they converge again through this same type of valve header back into the single 24 inch line. That point on

the Big Blue River is north of Fritch, Texas, north of the Canadian River, in Moore County.

This was not the first crossing we built over that stream. We first had a submerged crossing, but that was one case where our analysis of the stream bed proved in error. We were completely deceived by the shifting nature of the channel and lost this pipeline twice, and finally had to resort to this overhead crossing. I might explain that this river was never considered sufficiently treacherous in the first instance and we were not convinced by the first failure that we could not lick it with a submerged crossing. We hesitated to go to the overhead crossing because of what we felt was a bad abutment condition on the north side of the river. On the south side we had good abutments, good location for bridge purposes, but on the north side it was not considered favorable. To date our efforts have prevailed. The bridge is still in place and seems to be standing up very, very well. The photograph is taken from a point looking north. In the forefront you see the south abutment. This is typical of what I have described as the suspension type of river crossing. It is a specially designed pipeline suspension bridge.

(EXHIBIT NO. 78 for identification, offered and received in evidence without objection.

Document consisting of two photographs bearing the designations "392" and "544", respectively, marked Exhibit No. 79 for identification.)

Exhibit 79 is now called to my attention. This exhibit carries two photographs. The one at the top, designated as photograph No. 392, is of the Canadian River in Hutchinson County, Texas, at the point where Texoma Natural Gas Company's main line crosses enroute to Gray, Oklahoma—or Gray Junction, Oklahoma. This picture shows a typical submerged pipeline crossing under construction. The 24 inch main line has been reduced through a valve manifold header to connect with six 12 inch lines which are laid in the stream bed.

375 This lower picture is typical of many manifolds used in constructing submerged river crossings by Texoma and Natural Gas Pipeline Company, but does not cover another type where 18 inch lines emanate from a 24, the two 18 inch lines going into separate headers from which emanate three 12 inch lines each, so that the result is finally that the 24 inch line is broken down into six 12

inch lines which are laid in the stream bed. This type of crossing is used where the banks of the stream are not sharp bluffs, but where there are flood valleys on each side of the normal stream bed. In that instance the 24 inch line is stopped on high ground above the flood area. It is broken into two 18 inch lines by this valve header which I have described, and they traverse the flood valley. When they approach the river bank each of the 18 inch lines through a header construction is reduced to three 12 inch lines, or a total of six 12 inch lines altogether, and the 12 inch lines are then laid in the stream bed.

There are two very important reasons why we don't just lay our 24 inch line down across the flood valley and across the bed of the river instead of breaking it first into two 18 inch lines and each one of those into three 12 inch lines. One is safety and the other is the difficulty of handling a 24 inch line under those conditions where you are trying to dredge a trench in the bottom of a flowing stream and get your pipe down below the normal stream bed.

If there is no rock in the stream bed, the problem of getting the pipe down below the normal stream bed where a stream is filled with water is comparatively simple. You can go in with a drag line, and a drag line might be described in an elementary way as a shovel attached to cables operated from the boom of a tractor which rests on a barge or on the bank of a stream. The trench is dredged across the stream at the point where the submerged crossing is to be laid and the pipe is then lowered into this trench and an attempt is made to get it below the contour of the stream bed and sufficiently low that any channel change will not cause the line to become exposed and subject to being damaged by ice gorges or drifting tree stumps, which might result in the line being pulled out.

If there is rock in the stream bed, as you often encounter, then it is a case of drilling the stream bed and injecting or using dynamite in shooting a trench across.

The streams that were navigable streams had government inspectors from the War Department inspecting that work as it went in, to make sure that these pipelines were well below the stream bed and would not interfere with the use of barges or boats that might be passing on those streams.

When we got to such large streams as the Missouri River and the Mississippi River, those drag lines were operated from barges. They installed the tractor and the cranes on the barge and floated across the river
376 and opened a trench by the means I have just described.

I spoke of the safety involved in reducing the line from one 24 inch line, leaving off at the high point of the river bank, going across the flood valley, if there happened to be one at the crossing, to two 18 inch lines, and then reducing each of those to three 12 inch lines. The safety factor involved in that sort of an arrangement is expressed in one way by the statement that there is safety in numbers. The theory involved is that through the flood valley, if you should lose one 18 inch line, there is a possibility that the other may remain in service. If you lose one 18 inch line and the other remains in service and is not lost, you still have an opportunity of maintaining some sort of service for your domestic customers. Continuity of service is an all-important element in transporting natural gas into a metropolitan district such as Chicago, where over three million people are dependent for their comfort and convenience upon the heat which is supplied by the distributing companies from natural gas.

There is a great deal of buoyancy in a 24 inch pipeline. Even these 18 inch lines have to be loaded, anchored or weighted across these flood valleys. There is always the danger that those lines may float up and be washed out as a result of drift wood or trees. During the flood period there is always a lot of drift lodging against these lines and breaking them; so the lines, even the 18 inch lines, are thoroughly loaded and weighted across the flood valleys, and when we pass from the 18 inch to the 12 inch, these 12 inch lines are always anchored with heavy cast iron river clamps, which you can see in picture 392 at the top of Exhibit 79. Those little dots which appear on those lines in the stream bed are heavy cast iron river clamps which are installed upon the pipe to help hold it down to prevent it from floating up. Those river clamps are also installed over the transverse weld which connects two contiguous joints of pipe, and tend to reinforce the welded joint at that point.

The upper photograph on Exhibit 79 shows that we got

away from the old geometric principle that a straight line is the shortest distance between two points, but there is a reason for this. This picture No. 392 shows the six 12 inch lines being laid in the stream bed, not exactly with the arc of a circle—it is more nearly a catenary. It is a curve upstream so that the force of the stream will tend to place the pipe and the welded joints in compression rather than in tension. If the lines were laid straight across the stream or curved downstream, the pressure of the water against the pipes would throw the pipelines in tension and the welded joints would be subject to a greater strain than they are where the lines are curved upstream. That is not a practice peculiar to the Canadian River crossing, but is that generally followed in the laying of these river crossing lines.

In looking at the picture, just in order that the defects of the picture may be made more clear, I would like to call attention to the fact that—we are standing on the north bank as we look at the picture and viewing the south bank—on the south bank you see two of the six 12 inch lines trenched and coming up the bluffs. The other
377 four lines may have been laid and back filled, but it is my conclusion from looking at the picture that they have not yet been trenched and carried up the bluffs. In the foreground, standing on the north bank, we see four trenches, and here I am quite sure that two of the six 12 inch lines are already in and back filled. By back filled I mean where the trench has been again filled with earth. This crossing is one where the banks of the stream are sufficiently high and there is no flood area adjoining the stream, so it is unnecessary to resort here to 18 inch lines. The 24 inch line through manifolded header connections goes directly into the six 12 inch lines.

My attention is called to the fact that in viewing the picture of that part of the system of lines as they go across the river there are but four lines which appear clearly in the foreground, and I have been speaking of six. If you look closely, I think you can see at about the maximum point of curvature in the bends two lines on the inside part of the curve there which have been practically covered. This Canadian River is, I think, perhaps the most treacherous river we have on the entire system, and yet that stream here is almost dry, and at times of the year you can actually drive across the stream bed and

yet at other times during flood season we actually know that the sand in the stream bed had been a churning mass of sand for a depth of 25 feet. Bridge piers from the loss of bridges on that stream have indicated that the surface materials have been carried down to that depth in that churning sand, so that during that period of high water, when there is a high head and high hydrostatic pressure exerted on these lines, they are subjected to tremendous strains.

This is one crossing that might ultimately have to be spanned with a bridge. We have been watching these lines most closely. Soundings on the lines have indicated that the shifting of the sands has caused these lines to depart materially from the original contour to which they were laid, and for the past two years we have included in our construction budget a sum of money for putting a suspension bridge across the river. That suspension bridge would cost in the neighborhood of $200,000 to $225,000, and the only reason it has not been constructed to date is that we are still placing our faith in this submerged crossing and hoping we can defer making the expenditure for a while longer; but that is a condition which would result in complete paralyzing of the pipeline if that crossing were lost.

Questions by the Examiner.

We did not attempt to get below the river bed there. I do not think, truthfully, that we knew the characteristics of that stream. In fact, I know we did not. We did not know the characteristics of that stream as thoroughly then as we do now. We have now had about ten years in which to observe them; and in that connection we cross quite near the Rock Island Railroad bridge, which I believe has been lost three times and rebuilt. The Canadian River Gas Company has lost its river crossings not far from our line. They have washed out. The Phillips Petroleum Company has gas lines across there in connection with their carbon black operations, and their lines have been lost.

378 This is probably a more treacherous stream today than the Mississippi River, and, odd as it may seem, the Missouri River is considered by us to be more treacherous than the Mississippi, and yet the Mississippi crossing

may be the next one that we will lose; but those are conditions that we cannot foretell, and it simply means that constant vigilance is required, and each year we take soundings on all these stream beds to try to see where our lines are and see where the changing of the channels of the stream is causing those lines to shift, and whether they are getting into serious tension.

As a point of engineering interest, just this last fall we discovered a leak in the Canadian River bed during a period of low water. Gas was bubbling up through the sandy stream bed, and a sounding of our line showed that the river lines had shifted materially; so on the north bank we cut one line, one of the 12 inch lines, just to try to measure the stress and ascertain to what extent these lines had passed from a position of being in compression to that of being in stress, and the line jumped apart. I have forgotten the exact distance, but I think it was six to 8 inches that the line jumped apart, showing that the line had passed from the original state of being in compression to that of being in tension. But that is something we have to watch and watch very closely, to make sure when they are getting into such a dangerous condition that some remedial work has to be done.

My attention is called to the white line in the left-hand trench on the near shore. At that time the line was painted with coal tar paint. It is a paint made from a coal tar base, and although it is a high melting point compound, it nevertheless has a tendency to soften under the heat which it absorbs during the hot summer days, in which this line was being laid, and there is a coating of whitewash put on top merely to lessen the amount of heat that is absorbed and to try to maintain the paint or enamel in a stiffer condition, or cause it to become less plastic. The whitewash is used just where the line is exposed during the hot summer days and there is some delay in getting the pipe into the ground.

As to the difference in loading an 18 inch line and using river clamps on a 12 inch line, there are a number of different methods. 12 inch river clamps are quite conveniently installed for lowering into submerged position through the use of cast iron. With the 18 inch lines which are laid across the flood valleys, we are naturally working, at the time the pipeline is laid, under favorable conditions; at least, presumably we are, and we are not work-

ing under water. Therefore, in those cases it is entirely possible to use a cheaper form of loading, which may be a pre-cast concrete block, or it may be cast in place, or in some cases where the soil is of such a texture that it will hold a pipe clamp, we have been able to resort to a pipe clamp or anchor which consists of a large auger, not dissimilar in its construction or design to a wood auger but obviously very much larger in diameter. It may be eight or ten inches in diameter. That is screwed down to a depth of ten or twelve feet, and the handle disconnected and a cable inserted into an eye of this anchor, and this comes up and then laps over the pipe, the
379 pipe being properly protected, and serves as an anchor to hold the pipe down. But in the stream beds the cast iron clamp represents the most practical way of giving added weight to the line.

Direct Examination Resumed by Mr. Morgan.

As between a 12 inch line and an 18 inch line, it is obvious that the smaller the diameter the more flexible the pipe. The smaller line is easier to bend and lay to an irregularly contoured stream bed than would be a stiff 18 or 24 inch pipe. It is necessary to have that many 12 inch lines in order to get the gas from one end of the 24 inch line over to where the 24 inch line is resumed on the other side of the stream because, in the first place, you do not want to retard your flow needlessly by providing less cross sectional area than you have in your 24 inch pipe, so an attempt is made to strike a practical balance between the cross sectional flowing area of your 24 inch line and your smaller lines into which you break it down.

You can not take as much gas through two 12 inch lines as through one 24 inch line at the same pressure. There is more space in a 24 inch diameter than there is in two twelves. I haven't the exact figure. My recollection is when we struck upon six 12 inch lines that we were approaching very, very closely the cross sectional area of one 24 inch line. As to whether it is slightly more or slightly less I do not remember, but it is not difficult to determine. The Examiner states that he has just figured it out in round numbers, and that, using pi as 3, the six 12 inch pipes would give about 648 square inches cross sectional area. One 24 inch line would have 432 square inches cross sectional area.

There is no uniformity in reducing the 24 inch line to six 12 inch lines in these river crossings. There have been a few instances, where we felt that the stream conditions were sufficiently stable, that we crossed those streams with two 18 inch lines. There was one other case, and that is the Missouri River, where we were fearful that six 12 inch lines might not best serve our requirements or the conditions imposed by the river, and we resorted there to ten 10 inch lines.

(EXHIBIT NO. 79 for identification, offered and received in evidence without objection.)

(June 29, 1939)

In commenting upon the failure of the submerged crossing across the Big Blue River in Moore County, Texas, attention was directed to the fact that two failures had occurred. I find upon reviewing our records that on May 17, 1935, one of the 18 inch submerged lines failed during a period of flood and high water. If the record did not clearly disclose the nature of this submerged crossing, I would like to state that in this instance two 18 inch lines were used in the river bed. On each side of the river these two 18 inch lines were manifolded through header connections into a single 24 inch line, as was discussed yesterday.

Again on August 1, 1935, one of the 18 inch lines was so misplaced and disabled as a result of another flood as 380 to make it unsafe for continued operation. As a result of these two experiences, it was deemed impractical to make further expenditures upon the submerged line, and an overhead bridge type of crossing was resorted to. The overhead suspension pipeline bridge was started in September, 1935, and completed in December, 1935.

On reviewing the record I find that some of the statements regarding the routing of the line were not made entirely clear yesterday, and I will attempt this morning to restate those parts which I think were not made clear.

The record reveals that I stated that a crossing was found at Rulo, and that Rulo was north of Plattsmouth, the point at which the pipeline actually crossed. This was an inadvertent error. Rulo is south of Plattsmouth. It is located in the southeast portion of Nebraska, about where I am indicating on Exhibit 77.

In discussing the circuitous routing actually followed, an attempt was made to outline the difficulties of following a more direct course, something more nearly approximating a straight line. I think it was quite clearly stated that our

difficulties with gas pipelines from experiences gained with the Cities Service Gas Company prior to 1929 convinced us that it was impractical to try to cross the river between Kansas City and St. Joe, other things being equal, and if it had been considered a desirable routing to cross the river at that point.

There were other considerations, however, which were pointed out in reference to the flint hills in northeastern Kansas and the north central part of Missouri, as well as the flood valleys of the Mississippi and Illinois Rivers; so we started working north from St. Joe up the Missouri River, seeking a suitable crossing. Rulo had some possibilities as a crossing and was quite seriously considered for some time. However, we considered Plattsmouth far superior, not only as a river crossing, but the nature of the stream, the terrain and the topography from Plattsmouth east presented better conditions than from Rulo east. The only two crossings which were deemed at all suitable were the Rulo and the Plattsmouth crossings on the Missouri River.

In response to the question as to the difference in the length of a direct line and the routing of the line as actually laid, I would point out that the theoretically shortest distance in a straight line was never seriously considered, because a paper study indicated very definitely that this would encounter difficulties from the Missouri River on east and north to Joliet that would make such a line not only impractical but prohibitive from the standpoint of first cost and maintenance and upkeep in the later years of operation. We did consider quite seriously the cost of a line routed through Rulo and from Rulo east, but selected the more northerly point at Plattsmouth for the reasons I have already outlined.

381 The difference between the length of the line as laid and the length of the line had it been laid through Rulo from the field to Joliet is a distance of approximately 25 miles. It varies between 25 and 30.

Our studies did not always start from Fritch. At one time we were considering starting from Dumas, in Moore County. So, depending upon the point of origin and the terminus of the line, and certain irregularities and deviations which were necessary to consider in getting across these various rivers, the difference between the line as laid and the line had it been laid through Rulo is a distance of 25 to 30 miles.

This line is not obviously as straight as it is shown on this map. There are many little detours which are necessary because of right of way difficulties, topography, stream crossings, etc., which made it follow more or less an irregular course which it is not possible to portray on a map of this scale.

Had it been possible to run a line on a theoretically straight line routing, that distance would have been approximately 50 miles less than the routing of the line as laid.

I have the difference in flowing capacity of a 24 inch line, six 12 inch lines and two 18 inch lines. The flowing capacity of six 12 inch lines used in the stream bed of multiple river crossings is approximately 4% in excess of the flowing capacity of a single 24 inch line. Two 18 inch lines, frequently used by this company cross flood valleys, have a combined flowing capacity of approximately 9% less than a single 24 inch line.

In locating the stations, the slight pressure drop which would result from the use of two 18 inch lines in place of a single 24 inch line is taken into account, if there is enough 18 inch line laid between stations to cause an appreciable amount of pressure drop. Obviously, it is impossible to obtain in commercial sizes an exact balance between the multiple lines used when crossing rivers, so that the two 18 inch lines, with a slightly lesser flowing capacity than a 24, imposed no practical difficulty.

We have been talking about the 24 inch line and the various steps we took to try to obtain the right sort of pipe, and to test it, and to see that that character of pipe was finally installed in the pipeline; and we have talked about river crossings and other difficulties in connection with the construction of the pipeline. My testimony on that subject applies to all of our 24 inch lines, including the line of Texoma from Fritch to Gray Junction and the main gathering lines of Texoma, and we even went beyond that. We were no less diligent in our specifications and supervision of construction of the smaller lines. They all received the same degree of attention.

By smaller lines I meant the gathering lines. The company has in the field a main 24 inch gathering system, and then radiating from that are smaller sized trunk lines, and then the individual wells may connect with pipe as small as six or eight inch.

382 There has been something said in my testimony about compressor stations. The gas leaving the wells has an initial pressure imparted by nature, which we term rock pressure. As the gas flows from the well through the pipeline, this pressure is dissipated as a result of friction within the line; and when the initial rock pressure has been dissipated to the point where the gas can be no longer propelled through the line in economic quantities, it is necessary to again elevate that pressure through artificial means.

A compressor station is often referred to as a pump station, and the pumping of gas for all practical purposes is no different than the pumping of any other fluid, except that your pump is termed a compressor.

In transporting gas from the Texas Panhandle field to Chicago we were able in the early years to depend upon the rock pressure of the wells to transport the gas through the field gathering system to the initial compressor station located at Fritch, Texas. As the rock pressure recedes, we have to put in field boosters or compressors or pumps to elevate the pressure in order that it may arrive at the intake side of the Fritch station at an economic pressure for pumping from Fritch to the next station on the line in the direction of Chicago.

Some of the pressures have declined in our wells to a point where we have found it necessary to install compressor stations. We have already started to install field compressor stations; but our program was somewhat retarded through being able to make a fortunate exchange agreement with another company which enabled us to trade the gas from some of our low pressure wells to another company and in return we were able to get some high pressure gas delivered into our Fritch station. That fortunate turn of events, however, is only for a short time, and we anticipate in future years that it will be necessary to boost the gas from every well in the field. We have one station installed; but others are being installed by other companies who have experienced this same difficulty. That problem will confront all the pipelines.

Cross-Examination Interposed by Mr. Slaff.

That exchange agreement was made with the Phillips Petroleum Company, and the period of the agreement was originally for five years and there are three and one-half years left to run. The consideration of the contract is pri-

marily the exchange of equal quantities of gas. The quantity varies, as it of necessity must in the operation of such a contract involving wells; but I think the amount averages about twelve million cubic feet per day. I am advised that the maximum was eighteen. At the present time it has been averaging quite a little less than that. I do not think that contract is filed with the Federal Power Commission but it can be made available to you at any time.

In connection with my statement regarding the care the company took in designing and the taking of the necessary steps with respect to the Texoma property and the gathering lines, I did not mean to infer that the gathering
383 system was designed for 800 pounds pressure.

Direct Examination Resumed by Mr. Morgan.

Including the initial station at Fritch, we have a total of ten compressor stations on our main line. They are located at intervals of approximately 90 miles. The station west of Joliet is located at Geneseo, Illinois, and I think the distance from Joliet is 110 miles, but I would not be sure.

In these compressor stations, we have first the main units, and these are gas engine driven compressors, each of which is driven by 1250 horse power engines, and in each of the main line stations there are five such units, with the following exceptions: Station No. 1 has fifteen such units, and Stations 2, 3 and 9 have six such units. One of those units weighs about 400,000 pounds. There is a total in the ten stations of sixty-three of these big main line units.

In addition to the main line units there are auxiliary units, and these auxiliary units provide electric current through gas engine driven generators for doing the pumping of water, circulating water, that is needed in the plant for the operation of the compressor, the air compressors for providing starting air for the units, for operating the machine shop in connection with each one of these stations, and otherwise providing auxiliary power around the plant.

The other facilities around the station include water wells and water tanks, cottages for the employees, and such facilities as would be needed for the comfort and convenience of the thirty to thirty-five employees operating each one of those stations.

For the most part those stations are remotely located from any cities of any size. That is a condition over which we have no control, as the pipeline design dictates the lo-

cation of the stations and it is impossible to locate the stations at the points that might be most convenient with reference to obtaining labor and maintaining satisfactory labor relations.

The number of men employed in station work at each one of those stations varies slightly, depending upon local conditions, but in general the number will vary from 27 to 35. We try to provide living quarters for those men who are employed in these stations. In the absence of our providing them, there are no convenient living quarters available at those stations or very near them. The men have had to live at farm houses, and some of them with their own cars travel distances of 25 to 40 miles. Living quarters near the stations are not plentiful.

We have tried to provide suitable housing facilities and living quarters for our key men. We have to keep at the station at all times, 24 hours a day and seven days a week, a staff capable of maintaining the station in an operating condition and to take care of emergency repairs; so we have found it necessary, not only as an operating necessity,

to provide housing facilities, but more and more as the
384 trend of conditions between employer and employee

has changed, we have found it necessary to provide an increased number of houses. To maintain satisfactory relationships with the employees we have each year tried to meet the current conditions and have added the minimum number of houses which we felt were required to meet this condition; but each year we are building more, and ultimately, and in the not distant future, we expect that each one of our stations will have sufficient houses to take care of our complete personnel. Obviously, if we cannot take care of all the men there is dissension created through the feeling that, as the result of partiality or seniority, or some other condition that the employee does not fully understand, he is being discriminated against if he does not get a company house, and ultimately that housing program will be carried through. Each year we are adding additional houses.

In addition to that, on this subject of public relations, which is near and dear to my heart, we are trying to take care of the welfare of the employees with recreation facilities, for the children as well as the grown-ups, because of the isolated nature of the location of the places at which they are forced to live, and we have not lost sight of the

relationship which depends upon the attitude of the employee toward the employer.

When I spoke of the number of men employed at each station as being from 27 to 35, that does not apply to our Fritch Station. The Fritch station is the largest station of the system and has often been referred to as the largest compressor station in the world. I think, though, that some other company has challenged that, and probably rightly. There may be one larger than that; but this Fritch station, if probably not the largest, is the second largest station in the world, and requires a staff of about 70 men. The number varies from 65 to 70 men to operate the station, and then at that station, as was described yesterday, we have located the gasoline plant, and that requires an additional 30 men. Then the refrigeration plant is also located there, and that takes five to ten men for the operation of that plant. By refrigeration plant I mean the dehydrating plant. Then there are also at that station the men operating and maintaining the field pipeline gathering system and the main line north to Gray Junction, Oklahoma. I think there are about 45 or 50 men in the pipeline division.

Fritch station is designated as No. 1, and then the stations are numbered progressively from Fritch toward Joliet, 2, 3, 4, 5, 6, and so on. Station No. 10, as referred to, is at Geneseo, Illinois, and that is the last station on the terminus end of the line.

I have heretofore been discussing the problems we encountered and the efforts we made to solve those problems having to do with the finding of proper pipe and these various other matters. I have now located the pipeline, obtained the right of way, and described how the pipeline was built; but I have not said anything about the gas to be transported through that pipeline. Problems concerning that subject presented themselves in the beginning of this project.

After the line was completed we then started to test 385 it, and just preceding the testing the line was purged.

At intervals of about ten miles the line was opened at the point of a coupling and what is termed as a blowing unit was installed. This is a connection for conveying through a nozzle the gas from the end of the pipeline up into the air as pressure is applied from the field end. In this method the mill scale and any sand or foreign matter that might have been left in the pipeline during the period of construction was blown out of the line, and as each suc-

cessive ten mile section was purged, the line was again connected where the blowing unit had been removed, and then the line was tested under pressure up to 800 pounds to determine whether the transverse welding developed leaks, or whether the couplings were ironbound; that is to say, whether the rubber gasket had been pinched, thus permitting gas to leak through the coupling, or whether there were any defects in the valves or the swage drains which were used for draining off any moisture that might accumulate and get past the dehydration plant. In other words, the testing of the line was to determine mechanical or material defects in the construction.

In the same way the engines and compressors were put through performance tests before acceptance from the manufacturer to ascertain that they would meet the specified requirements; and every facility to be used in the operation of the line was tested after the line was completed.

The gas used in blowing the line and in making those tests was obtained from the Canadian River or the Colorado Interstate Gas Company. They caused it to be furnished from Canadian River. The Colorado Interstate Gas Company is the company which I said we were successful in getting to commit a part of our pipeline requirements in connection with my discussion of the participants.

At the time we completed our pipeline we had acquired gas reserves of our own, to which we acquired title August 21, 1931.

Going back to the year 1929 when I went to New York for the purpose of devoting my entire time to the problems of organizing this pipeline project and putting it into operation, I spent a great deal of time in considering the subject of reserves from the time I first went to New York. By that time we had learned that there was a gas field of magnitude in the Texas Panhandle; but we did not know at that time the extent of that gas reservoir and the magnitude of the reserves contained within that reservoir as we know it now.

I stated yesterday that we knew more about it than we did in 1926, and we know more about it today in 1939 than we did in 1929; but in 1929, 1930 and 1931 we knew there was a field there of magnitude but there was no way then of determining from geological information, based on what authentic well logs we had, the accurate boundaries of the field. There was no way of knowing the extent of sweet

gas or the line of demarcation between sweet and sour gas. We knew that some portions of the field were productive of sour gas and others sweet. We knew that some por-
tions of the field were capable of producing very
386 prolific wells and others dry holes and non-commercial wells. We knew that there were certain portions of the field which were productive of oil, but as to the extent of the oil and to what extent the field might be butchered up by oil production we had no way of definitely knowing. I am speaking from the standpoint of a gas man now, and not an oil man. I use the term "butchered up" because one of the things that frightened us most about the Panhandle field as a dependable gas reserve for a pipeline of this magnitude was our lack of knowledge as to the extent of the oil production.

That was important for a number of reasons. The local markets had already been served with natural gas and were inadequate to provide a market for any appreciable quantity of the gas which was known to be available, and no pipelines had been built to distant markets, such as Chicago, so that gas did not appear to the State or the oil producers to have any particular value. The State had not made any attempt to enforce a rigid conservation policy, and the oil producers were only concerned with natural gas as a by-product or a means of helping them to lift their oil. The use in casinghead plants was just a by-product and wasn't a major consideration with the oil producer. The oil producer was intent upon getting the maximum amount of oil possible, and if gas was encountered above the oil it was the usual practice to rip the casing or to raise the casing seat so as to let the upper gas in as a means of helping to flow the oil well.

This practice was so prevalent that even in the early days it was apparent that the pressures in the oil area of the field were going to be rapidly dissipated, and any opportunity of depending upon gas leases in that territory as a dependable reserve was lessened by the failure of the State to enforce oil-gas ratios or a rigid conservation policy with reference to trying to preserve the gas; and the extent of those oil fields was one of our major worries. If our leases turned out to be near an oil field, the consequence under the practices in the oil field was that the gas would not be preserved for future use of the pipeline, but would be rapidly drained from under our lease through the oil development.

In selecting our reserves of gas throughout the field we had to rely upon the best information available in trying to select our acreage and our reserves as intelligently as we could in the light of the facts as they then existed. To begin with, we had to take into account the outer boundaries of the field. We had a general feeling that we knew something about the boundaries of the field; but it later developed that we did not, or at least, not all about it. I think we knew something about it; but we did not know as much about it as we thought the data at that time warranted us in determining or accepting as the boundaries, and we did get some of our acreage too far out. We also had some information regarding what we thought was the line of demarcation between the sweet and the sour gas parts of the field; but that line was based upon long distance interpolations between the wells which had been drilled. We might find a sour gas well and it would be ten miles to the nearest well, which might be sweet. Some place in between in that ten mile gap we felt pretty sure the sweet gas line would pass, but as to whether it
387 was a mile from the sweet gas well, or five miles away, there was no way of determining except by interpolation, and interpolation was to a large extent based on the sulphur content in the sour well, the degree of sourness, so that was another factor.

We were also conscious that some dry holes had been drilled. Those were the areas to be avoided as far as possible. There were other areas where small non-commercial wells had been drilled, and others where very large productive wells had been drilled; and then, of course, as I stated, we tried as far as we could to avoid those areas which our geologists said were most likely to be productive of oil, geologically, based upon the information they had.

There was nothing very definite. In retrospect, there was not anything as definite as we thought to guide us in the selection of our acreage.

At the time we were studying our problem of assembling gas reserves to put back of this pipeline project, the situation in the Panhandle was that practically all of the mineral rights, the oil and gas leases, had been contracted to large companies and lease brokers, and they were out of the hands of the lessor, the landowner. The field had been practically leased in its entirety, solidly leased, and because of the lack of knowledge as to the boundaries of

the field, much of the surrounding countryside for miles outside the field was also under lease. There had been some leasing going on there for ten or fifteen years, but the activity was greatest from 1926 to 1930.

As to the terms of an ordinary oil and gas lease providing for keeping it alive after it is executed, of course, leases vary some; but in general they were quite uniform in their terms, and the way in which the lease might be kept alive was through the payment of rentals which were called delay rentals, either on an annual or semi-annual basis, and the reason they were termed delay rentals was that the rental was a payment in lieu of development, or the drilling of a well. The lease as a usual thing provided that the lessee, or the party to whom the land owner granted the mineral rights, should have the lease on the minerals for a primary term of five to ten years—that term varied in different leases—for the consideration of an annual rental payment or the drilling of a well. If the well resulted in production, the usual lease provided that the rentals would cease and that the lessee would enjoy the privileges of producing the minerals under stipulated royalty conditions, so long as oil or gas might be produced thereafter in commercial quantities.

Those leases, having been taken prior to 1930, mostly in 1926, had been kept alive for the most part over the great territory included in the field and around the field by the payment of rentals. The usual rental is $1.00 an acre, although I recall back in the very early days with the Empire Gas & Fuel Company we had leases out there that called for a rental of ten cents an acre; but that was so far in advance of the development of that field and our knowledge of what was contained there that much of that acreage we had under lease was allowed to lapse at the
388 end of the primary term, and a condition of one of those leases that has just been described is that at the end of the primary term, if the lease has not been drilled, all rights of the lessee lapse as of the expiration date of the primary term and he no longer has any privileges. The lease then reverts to the land owner or the lessor, and he is then privileged to make another contract with somebody else who may be interested in paying a premium or a bonus for the privilege of entering into a lease agreement such as I have just described.

(Map entitled "Texas Panhandle, Oil and Gas Leases

in Effect, August, 1930", marked Exhibit No. 80 for identification.

Map entitled "Leases Owned by the Texoma Natural Gas Company in Texas Panhandle Gas Field, August 1, 1931," marked Exhibit No. 81 for identification.)

While we took the title to our reserves in August, 1931, commitments had been made for those reserves about 60 or 90 days, or perhaps longer than that, prior to that time. Some commitments had been made during the year 1930.

Exhibit 80 was prepared under my direction. The heavy black line is the boundary line as conceived by the Texas Railroad Commission in 1937. The areas colored in red represent the lands under lease in August, 1930. I have said those leases belonged to large companies. For the most part they were large oil companies. There were some gas leases in there that were held as gas reserves, such as those held by the Canadian River Gas Company, to which we referred yesterday. For the most part, however, the leases were held by large oil companies. The white patches throughout the field on the remaining part of the map represent the lands which were not at that time under lease.

At the time we were considering the question of assembling reserves for our pipeline, our prime motive was to be sure that we got an adequate supply of gas to take care of this pipeline project. Under the conditions which I have described as to the location of oil fields that were then known, as well as those which might be developed which were unknown as to their location, the fact that some portions of the field were highly productive and others nonproductive or productive only to a comparatively small extent, and the uncertainty as to the limits of the field and the location of the sour gas line, it was our judgment that the safest way of acquiring our acreage would be to get a widespread play—I term it widespread—meaning to try to scatter our play through the various areas, and by the term "scatter" I do not mean we were seeking scattered tracts, but to spread our play throughout the different areas so as to eliminate the possibility of getting our eggs all in one basket and having our entire gas reserve destroyed through a lack of judgment in locating the points at which it was to be selected, or finding later that the points which we had selected might turn out to be an oil pool or a sour gas field or a barren spot, though we had upon the information then available considered such points to be the more prolific part of the field.

When I spoke of having an oil pool right in the midst of it, I was thinking about further development of oil, which meant the dissipation of the gas reserves and the destroying of that reserve for a pipeline. Continuing
389 exploration for the discovery of oil in that field was being carried on at that time and is continuing today. New oil pools and new areas producing oil have been discovered since we acquired our reserves, and some of them turned out to be in the vicinity of the reserves which we had acquired.

It would not have been possible for us to block up our gas reserves in one place in that field under the conditions that then existed; but that did not disturb us because we did not know of any single spot into which we wanted to concentrate our entire holdings.

I have spoken of the participants in this project, the Texas Company, the Phillips Petroleum Company, the Skelly Oil Company, and the Columbian Carbon Company, as owning substantial reserves of gas in that field. Each one of them had a wide spread over a vast part of the field. The strategy which they employed in assembling their holdings was not greatly different from ours. They did not have any more information than we did about the oil or the gas, so they were taking spreads in the same way. One other reason is that while there are some large ranches in Texas, there are very few of them that have been retained in a solid block or retained intact. Many of them are broken down and have been leased to many different operators. The Burke Burnett ranch, which was acquired almost in its entirety by the Cities Service Gas Company, has many spots in it which were leased to the Gulf Production Company, the Texas Company, the Phillips Petroleum Company, and Skelly Oil Company, so that, although there were large ranches, even those large ranches were frequently broken down into smaller tracts and leased to different companies, and it was impossible to get any big solidly blocked lease in any part of the field, with very few exceptions.

We did not start out to buy the gas at the wells from the then owners of the leases. We were definitely committed to a policy of owning or controlling our own gas reserves, our own leases. We regarded that as the more desirable course to pursue because we had had years of experience in the midcontinent field with Cities Service Gas Company, and we knew the operating ills and difficulties

of a gas purchase policy in trying to supply a pipeline with purchased gas, and we also appreciated the advantages of owning and controlling the leases on which we could control our own production and drilling program and the production from those wells to maintain a constant and adequate supply for our pipeline. Based upon that experience we were definitely committed when we entered into this project, as were all the participants, that the project should own its own reserves, and we were equally firm in our conviction against the purchase of gas.

In the midcontinent field Cities Service Gas Company had attempted to operate by the purchase of gas, and they are still today buying some gas in that field.

We did not buy a part of the Canadian River gas reserve on which I have stated the Standard through some of its connections had a call; but we were successful in negotiating a contract for placing behind this pipeline
390 a call for 25% of our pipeline's requirements from that reserve.

I would not construe that as pursuing the policy of purchasing gas, because there in that case we had a call upon a reserve which was being developed by a substantial company for pipeline use. Their primary interest was the development of that reserve for the Colorado Interstate pipeline going to Denver and lines emanating from that same reserve and working south. We did not look upon that contract as having the same evils that we would be faced with in purchasing promiscuously from small lease owners who might drill one well or ten wells and whose primary interest was not in the pipeline. Their primary interests might not be in selling gas. It might be just a side play, and when we were in need of additional open flow for our pipeline, it might be that the financial necessities of that man or that company might be such that they would not be particularly concerned with drilling more wells.

Another thing, we had the experience in the midcontinent field with the Cities Service Company that producers from whom we purchased gas took less interest in the maintaining of their wells in a good operating condition. As the result of inflow of water or caving formations falling down into the open hole, the flow from the well might be almost completely plugged off.

There are other instances where in the winter time when the gas is most needed by the pipeline that due to moisture in the well, the well or the connections to the well might

freeze up. The average producer does not concern himself about that. It is not a matter of great moment to him. If he does not get his well operating today, maybe he will tomorrow; but with the pipeline it is a matter of continuous flow, and during those cold weather periods, the very existence of the pipeline, continuity of service, depends upon our having control of those wells and knowing that every hour of the day we are going to be able to depend upon that supply.

So we just felt that we could not under these conditions depend upon anything other than our full control of every phase of our operation. This gas does not flow from the Texas Panhandle to Chicago in an hour. It is a period of over three days from the time the gas leaves the Texas Panhandle until it reaches the Chicago markets, and it is not possible for us to successfully handle the production from these wells unless we have control of every facility.

The acquiring of these reserves was a matter of negotiation. We had in mind the spreading of our play throughout the field. We selected the acreage that we felt was best suited for our requirements and then it was a matter of negotiation in trying to get the best price possible.

In addition to the acreage which was held by the participants, which we hoped to acquire and did acquire through negotiations, we were also interested in additional acreage which was not owned or controlled by anybody
391 interested in the pipeline or in any manner affiliated with any of the participants, and one very good example of that is the Magnolia block in Moore County which was owned by the Magnolia Petroleum Company, an oil company down in Texas. They also had some acreage in Carson County which we thought at the time was favorably located, and has since proven to be. In the case of those purchases we entered into negotiations with the officials of the Magnolia Petroleum Company and arranged for the purchase of their gas leases in the Texas Panhandle field. They had a little over 50,000 acres down there, partly in Moore County and partly in Carson County. The Moore County acreage is that large red block which you see almost in the center of Moore County on Exhibit 81. The most of that comprises the Magnolia acreage in Moore County. That is the largest single block of acreage we have under a common ownership.

The other acreage acquired from the Magnolia in Carson County was a block of eight sections located in the

northeastern part of Carson County, which is shown as almost a solid block here at this point on Exhibit 81.

They had a few scattered tracts which were not embodied in these blocks and they were tendered to us at the same time. We undertook to negotiate with them for the purchase of these two large tracts and exclude the other acreage. We tried to select that acreage which we felt represented choice acreage, which we were most desirous of obtaining; but they were not interested in allowing us to hand pick or sort over their acreage. They were willing to negotiate a sale at their price for their gas rights in the Panhandle; and the price of all their rights was two million dollars.

We explained to them that some of their acreage was not well located, and we were not interested in it; but we were very firmly informed that we could take or leave such parts as we wished, but that the price for that which we did take would be two million dollars. We took it all. We had no choice. They were unwilling to let us select the acreage and leave with them the culls which we thought had little value. And if we thought so, they knew it, as it was a matter of common knowledge at that time, and it would leave them without a sale to somebody else.

In purchasing this 50,000 acres from the Magonlia Petroleum Company we were not thinking in terms of the number of acres embraced within the entire purchase. We were thinking of gas reserves and an adequate supply of gas for this entire pipeline project. I think we are often confused in speaking of acres when we deal with reserves of gas for a pipeline, unless when we use the term "acre" we associate with it the average quantity of gas still in place or that is recoverable, or we go beyond the mere designation of acres. Acres is merely a surface unit of measurement and has nothing to do necessarily with the quantity of gas which may be in the reserve under a given number of acres. To that extent I think the term acreage in figuring on gas reserves is something of a misnomer. We were after a supply of gas for our gas pipeline company.

392 At the time we made this purchase from the Magnolia Company, for example, we did not expect to retain permanently and produce from all of the acreage that we purchased from it. We knew that some of it, or we felt we knew that part of it, would not be worth paying rentals on and carrying, and as soon as we could determine such

parts of the acreage as we thought were of little or no value, they would be discarded as a means of stopping rentals, taxes and fixed charges on them.

We did not know at the time we purchased those large tracts which portions would be discarded or which we would ultimately retain. We were relying on the development of those tracts and the drilling of wells by others to guide us in our policy of sorting over and eliminating and acquiring additional acreage to keep our reserves rounded out.

Texoma Natural Gas Company was organized May 26, 1930, and was in existence at the time the title was taken to the acreage on August 21, 1931. Texoma, as I recall, was not in existence at the time the title was taken to the Magnolia block. That was taken in my name as trustee and later transferred to Texoma when that corporation was created.

(At this point counsel for defendants, in reply to questions of the Examiner, stated that the Magnolia Company is the Magnolia Petroleum Company, an oil and gas company which operates in the State of Texas; that it is a major oil company and is a subsidiary of Standard Oil Company of New York; and is still in operation.)

There was no affiliation or relation between the Magnolia Petroleum Company and this pipeline company, and it was not interested directly or indirectly in this pipeline. The fact that it is a subsidiary of the Standard of New York should not in any way confuse it as having any connection with the participant, Standard of New Jersey.

As a matter of fact, the Magnolia Petroleum Company has probably been one of our most troublesome lessors, and has repeatedly threatened damage litigation for what they claim is failure to provide for adequate development and taking care of drainage from that lease; so that they are not only not interested in the company, but they are perhaps one of our least cooperative lessors. They are lessors of ours in that they own some of the land in fee, so they are land owners and own the mineral rights to part of the acreage. They own the fee to the acreage which was obtained in Carson County; but to the acreage held in Moore County they do not own the fee. We have an operating agreement with them as to the lands held in Moore County. They retain the oil rights and we the gas rights on acreage which was owned in fee by third parties. In other words, we purchased from them only the gas

393 rights and not the oil rights. In this land which they owned in fee they own the royalty to the gas rights, and on the land in which they owned a leasehold interest only, they retained the oil rights. They have drilled wells to get oil and we have drilled wells to get gas; so we had to have an understanding and an agreement concerning our relative operations there, each in his own field. That is what I was talking about when I spoke about the contractual arrangement as between their rights in the oil and ours in the gas.

There were other tracts of land in the field which were large, not in the sense of being in a solid block but in the sense that they embraced substantial quantities of acreage, except that owned by the Magnolia and those owned by the companies which I have described as participants in this pipeline. There was another block of acreage in Moore County on which we looked with favor, which was owned by the Shamrock Oil & Gas Company. This block, however, was eliminated from our negotiations because of the high price at which the gas rights were held. The Shamrock Company was unwilling to dispose of their gas rights for less than $100 per acre, and we felt that this price was excessive in consideration of the prices at which leases were then selling, and relying too upon our ability to obtain our necessary additional requirements at a lesser price, so we did not take on that acreage.

We purchased acreage from the other participants in the pipeline company, and by other, I mean other than the Standard Oil Company, which did not own any reserves there but had a call on some. I wish to make it clear that we did not acquire any acreage from the Standard, but entered into a contract with them to obtain 25% of our requirements from reserves upon which they had a call but which were owned by Canadian River Gas Company. That gas was delivered to us at Gray Junction, Oklahoma. We obtained gas reserves from all of the other participants in the project; and their ownership of these gas reserves was an important factor in our consideration of inviting them to participate in the project.

Cross-Examination Interposed by Mr. Slaff.

When I say "in our consideration" and "we obtained reserves," the "we" and "our" refer to the management of this company. When I say "their ownership of these

reserves was an important factor in our consideration of inviting them to participate in the project," I mean by the expression "our inviting them" the executives of the project. At that time and in the early development no corporate distinction had been made between the producing company and the transporting company. When I speak of this collective action of acquiring reserves, I am speaking of that group of men representing these companies who had gotten together and by mutual consent deemed that this project was a feasible one, and then started out to see what could be done in bringing the lease owners together.

Direct Examination Resumed by Mr. Morgan.

394 It was Mr. Henry L. Doherty who invited the Standard Oil and the other companies to participate in this project. When the acreage was acquired, however, I was in charge of the company's operations, and when I say "we" I am referring to the management which had been centered in me.

We conducted negotiations with the participants for the purchase of their acreage which became part of the reserve back of this project. That negotiation was not any different from negotiations with the non-affiliated owners of acreage in the field, except that I believe our negotiations were a little more prolonged and a little more strenuous than they were with some of the non-participating owners of acreage.

In the negotiation of the purchase of acreage from the Texas Company or any of those from whom we acquired acreage, it was, of course, just a matter of locating their acreage, getting a description of it, putting it on the map, and trying to see how it would fit in with other acreage we had in mind trying to acquire. Then it was simply a case of trying to negotiate the best possible price with that owner. We argued very much with the Texas Company about the price it wanted for its acreage, and also about how much acreage we would be required to purchase if we purchased any, and things of that sort. Some of those arguments were rather protracted and heated. That was true of the Cities Service, the Chicago utilities, and the others. It was no different with Cities Service than with any of the others.

As to the position in which I found myself and regarded

myself at the time I negotiated for the purchase of these reserves, I will state that the entire activity imposed upon me or in me was one of trust, in which I of necessity had to deal impartially with all the participants. There was to be no act that I could possibly perform that would reflect favoritism upon one participant to the detriment of another. That charge I respected and attempted to carry out to the best of my ability, and have to this date.

I made individual purchases or negotiations with each of the companies and fought it out with them as we did with the Magnolia Petroleum Company. However, those efforts were both individual and collective: I might meet with the Texas Company, with their geologists or construction engineers or their executives one day, and perhaps with the Phillips Petroleum men and Skelly and others in an effort to try to get a cross section of opinion as to what could be done. In the meantime we were compiling the acreage on the map, the acreage of all of the different groups, trying to see to what extent it could fit together and help work out efficient drilling units. We didn't consider it desirable to drill a well upon a 60 acre tract or an 80 acre tract; but that tract might have equal value to a full section if some of the participants had acreage contiguous to it or adjoining, so a larger unit could be worked out. That was part of our study in analyzing and appraising the usefulness of the acreage to us.

Then after getting a cross section of opinion, and finding that opinion varied, I met with the representatives of these companies in an effort to try to reach a settle-
395 ment on acreage values. The prices ranged considerably. The Texas Company felt that they would hold out for $55 per acre. As I recall, Phillips and Skelly felt that the acreage should command a price of at least $50. There was no real market value fixed in the field. Acreage was being acquired by lease brokers, and you were never able to determine exactly for whom they were purchasing. Title would be taken in their name as agent and might be held for a period of a month before it was assigned to the real party in interest.

Competition in the purchase of acreage at that time was a feature that really complicated the negotiations. About that time, in fact, almost simultaneously, three pipelines started from the Panhandle field in a northerly and northeasterly direction. The three major companies were the Northern Natural Gas Company, the Panhandle Eastern,

and the Chicago pipeline which we are discussing, the Natural Gas Pipeline Company of America. These companies were all interested in acquiring gas reserves in the Texas Panhandle field, and almost overnight these gas reserves, which had been looked upon as having little or no value except as by-product plays for oil operations, suddenly developed to have considerable value, and the market changed with equal rapidity from a buyer's market to a seller's market and the prices during that period of negotiation rose rapidly.

I don't know what the Shamrock would have sold their reserves for six months or a year earlier. I don't know what Magnolia would have asked for their reserves. My judgment is that it would have been less than the price asked or paid at this time in 1930 and 1931; but that was the situation which developed and which has characterized every play in an oil pool. In a new field, when a discovery well is brought in, almost overnight values go up because of the competitive purchasing, and the same type of leasing which takes place. Companies will rush in and take spreads in all directions without regard to geological information, with the view of letting their less desirable acreage go as they find that the geological information disproves its value.

We were not placed in quite that same situation because we had more idea of what we were trying to accomplish; but at the same time we did not have control of the market situation. We had to negotiate in competition with these other purchasers of leases in the field. These fluctuating values complicated our negotiations with the Texas Company, Phillips, Skelly, and others. There was not an established market price, but it was a matter of negotiation.

We finally settled upon a price of $45 an acre; and this was not a price satisfactory to the Texas Company, Phillips or Skelly. They felt that the market value of their acreage was more than that. They realized, however, if they were to enjoy any participation in the project they could not take their acreage and sell it to the Northern Natural, or the Panhandle Eastern, and still have a position in this project; so to that extent in negotiating a price we did have a negotiating advantage which we did not have with Magnolia.

We did not pay the same price for the acreage we ac-
396 quired from the Chicago utilities. There again was a dif-
ferent situation. The Chicago utilities had caused to be purchased for their account holdings of gas reserves of the

Gulf Production Company in the Panhandle field for which reserves they had contracted to pay a sum of five million dollars. We were desirous of procuring those reserves, and opened negotiations with the Chicago utilities' representatives in an effort to acquire those reserves. The utilities' owners took the position that they were willing to turn over to the project their contract of purchase for this acreage at the same price they had paid. They did not ask a profit, but they were unwilling to take a loss. We did acquire reserves from Texas, Cities Service, Phillips, Skelly, Columbian and the others at a lesser price; but it was not possible to procure the Gulf Production leases for a lesser price than the utilities had paid. They had acquired those reserves prior to their being invited to take a participation in the pipeline, and they were unwilling to take a loss. We wanted the acreage and we paid that price.

Questions by the Examiner.

As to how much the price per acre was, the acreage obtained was never accurately determined, but it was in the neighborhood of 108,000 acres, and at the price paid it was roughly in the neighborhood of $50 an acre.

Cross-Examination Interposed by Mr. Slaff.

That acreage was scattered from Moore County to Wheeler County, right down through the center of the field.

Direct Examination Resumed by Mr. Morgan.

When we took title to the acreage on August 21, 1931, we did not take title to the 108,000 acres of Gulf acreage. Some of this Gulf acreage which we felt was not worth retaining for future development fell somewhat in the same category as the Magnolia acreage which we rejected, but took title to and finally disposed of. Under this agreement with the Chicago utilities to take over that acreage, they retained administration of the contract until we had organized and were in a position actually to take over the administration of it. At that time we did not have our Amarillo office open, and we were not set up to take charge of the payment of the rentals and to watch lease expirations and development; so they took care of that until we were in position to take the contract over actively and administer it.

During that intervening period the rental on some of these leases fell due, and rather than to pay the rentals, or to pay renewals if they expired on acreage which we thought was of less value or no value, we surrendered them; so when it came to us on August 21, 1931, some portion of that acreage had been released, and we voluntarily, when we took title on August 21, combed it over to try to eliminate book work of taking over acreage which we thought had no value. We discarded part of it during the period when it was being administered by the utilities, and then when it came to us we dropped more at that time.

397 108,000 acres was not the amount of acreage that we ultimately kept. That was the original purchase by the utilities. In other words, they had contracted for the purchase of some 108,000 acres, and we had the right to acquire all of it, but some we discarded before it was assigned because we didn't think it was worth paying rental on and keeping it alive. We could have had every bit of the 108,000 acres. In fact, we took an assignment of their purchase contract. They did not make an outright purchase of acreage at all. It was on a payment of a million dollars a year; so we took over their contract to purchase, but felt in the interest of economy there was no need of taking title to acreage which would have no value to us later. It cost us more than $50 an acre when you consider the eliminations. We paid $5,000,000 for the right to take it all, and we got the acreage which was actually assigned for that $5,000,000, and that ran the price up to more than $50 for that to which we actually took title.

We regarded the acreage acquired from the Chicago utilities, and which they had acquired from the Gulf Production Company, as being worth the price which we agreed to pay and finally did pay for that acreage. We were extremely desirous of procuring that Gulf Acreage and felt that it was worth that; but when the eliminations were taken into consideration, the fact that that acreage was costing us more than we had paid Phillips, Cities Service, or Texas, was a matter of considerable contention because the other participants were not getting as much as was paid for the Gulf acreage. Nevertheless, we would have paid more for the Texas acreage and that of the others if it had been necessary, as we did for the Magnolia. It was a case of making the best possible deal for getting a supply of gas and acreage which fitted into our project.

We did not pay the Texas Company all that it wanted

for its acreage. We have had other occasions and opportunities to make trades with the Texas Company for the things it sold and for the things which were needed by this project. We have had other negotiations with that company and other participating companies for commodities other than acreage which were needed in our operations. The very nature of the operation of these companies has brought us into contact. At the time the pipeline was constructed one of our research and engineering problems was that of selecting a suitable pipe coating. We had some rather definite ideas about pipe coating from our experience in the midcontinent field; but when we started in to make definite plans for the building of this line, we realized, because of the variety of the soil conditions which we would encounter, with its corrosive nature and all, that we should recheck all of our studies and try to make sure that we obtained the best possible pipe and coating obtainable.

Our judgment finally was that a coal tar base was the
398 proper base for the pipeline paint. Two of our participants were engaged in the manufacture and sale of asphalt pipe paint, and a natural amount of pressure was exerted upon me to buy asphalt pipe paint for the line.

It was our considered judgment, however, that this was not the type of paint which was best suited for our need, and we purchased, at an expense of some $700,000, pipe paint from a disinterested outside concern.

I think that other dealings that we have had with the participants might illustrate the extent to which the affairs of this company have been kept separate and clear from the payment of high prices through lack of negotiations or through the throwing of business to one participant to the detriment of others. For instance, we use 35 to 40 carloads of salt each year in our water treating plant. One of our participants is a producer of salt and has striven for years to obtain that business from this company. To date they have not been able to meet the competitive price at which we can buy salt from outside disinterested concerns, so we are continuing to buy from a nonparticipating company.

When we started in to obtain quotations for rubber gaskets to be used with the couplings in constructing the line, one of our participants mentioned the reciprocal relations which they enjoyed with a rubber company, and urged that we give consideration to this rubber company in the pur-

chase of our rubber gaskets. The relation between that participating company and this rubber company was that they were supplying the rubber company with carbon black. Carbon black goes into the manufacture of gaskets and other rubber materials like automobile tires and things like that. These rubber gaskets which we were purchasing cost in the neighborhood of $100,000. This incident comes to my mind as I am telling of it. I can't today tell you whether the particular rubber company mentioned was the successful bidder or not; but that did not enter into our letting of the contract for the purchase of these rubber gaskets. I started to tell it; but I don't remember now whether that rubber company was the successful bidder or not, but the reciprocal trade relations enjoyed by this participating company with the rubber company did not influence our purchase of rubber gaskets. I remember that incident merely because I had been importuned by one of the participants. That is the type of relationship that has existed from the day this project was conceived down to the present time.

Something of that character has also arisen in connection with the disposition of our natural gasoline which we extract from the gas down at Fritch. Naturally, these oil companies which are participants in this project have been interested in procuring the gasoline output of our Fritch gasoline station. Our production from that plant runs in the neighborhood of 25,000,000 gallons of gasoline per year. The refiners and oil companies use the natural gasoline for blending in motor fuel, and with the connections they have through their sales organizations for selling natural gasoline to outsiders they have been interested in handling the output of this plant. However, the output of the plant has been sold under competitive bidding. At the pres-
399 ent time the Phillips Petroleum Company, which was at one time associated in this project but is no longer, is taking one-half of the output and the other half is going to the Columbian Gasoline Company, an affiliate of Columbian Carbon Company, which is a participating company. We do not favor the Columbian over the Phillips. The sales price to each of the companies, participating and non-participating, is the same and the contracts are on exactly the same basis.

A few gas wells had been drilled on the Gulf acreage at the time the Chicago utilities acquired it. I think there were eight, and those eight wells were included in the pur-

chase price and tended to give you some index of the producing capacity of that acreage. They came in with the contract to purchase acreage and it was all in the price of $5,000,000. Some of the other acreage which we acquired, like that of Texas, Cities Service, Phillips and Skelly, was already proven up by wells which had been drilled and which were conveyed to us at the same time. The Magnolia acreage in Moore County had no well on it, and it is my recollection that there was none in Carson County. I believe there were no wells on the Magnolia acreage at all.

The fact that some of the other blocks of acreage had wells already drilled on them gave us a better index to their value from the standpoint of actual production than that concerning the Magnolia acreage. In the first place, we had some index as to the reserves in place, as to whether or not the acreage was as good as we might have anticipated without that information. If the well was drilled we had a definite index as to the reserves and the value of the acreage. Further than that, the drilling of the well prevented the risk which we would undertake of getting a non-commercial well, a dry hole, or a sour gas well, so that did give quite a definite value by virtue of those wells having been drilled.

I have not dealt with the participating companies in the matter of acquiring acreage or in the matter of buying and selling any commodity which I had to buy, or which we had to sell, like gasoline, on any other basis than I did other people I negotiated with or who were negotiating with us concerning such operations. I can without hesitation say that there has never been one dollar of this company's money expended, or one transaction of any size ever entered into, which has not been for the best interests of the company, regardless of the detrimental effect it might have upon some participants in the company. If in my judgment the expenditure or the transaction was for the best interests of the company I represented, then that is the procedure that was followed, regardless of its effect upon participating companies.

I have in mind a fight that developed down in the State of Texas before the legislature of that State concerning this wastage of gas about which there has been testimony in the record. We took a very definite position of trying to protect our gas reserves and to oppose any statutes or commission orders which we felt were detrimental to the preservation of our gas reserves and to the conservation of

natural gas in the field. This developed a fight on the
400 subject of what is commonly called down there pro-
ration, or the question of whether or not we should divide our markets with others who did not have them in the field. That fight really turned on that point. The activity was always one of trying to force these pipeline companies, which had at considerable expense and hazard gone out and expended their money and created a market, to spread their gathering lines all over the field and buy promiscuously from everybody and create a market on a ratable basis. We ran into conflicting interests of some of our participants in that situation. I don't know that the oil companies which were participating in the project were ever fully satisfied that the interests of Texoma were consistent with the best interests of the oil companies. Nevertheless, we had only one course to pursue, and that was to fight for the best interests of Texoma.

One of our oil company participants actually sent their representative into the hearings in Austin before the Committee dealing with this legislation, and took a position diametrically opposed to the representatives of Texoma. He stated to me, and other officials of that company stated to me, that they felt that their oil interests were apt to be injured by the position that Texoma was taking—so injured that they felt they had better, as they expressed it, throw their interest in the pipeline project out of the window and take the position of trying to protect their oil properties and let the gas go.

Cross-Examination Interposed by Mr. Slaff.

Mr. Slaff has inquired the name of that company. In answering this question my own reluctance in disclosing the name is because of the very cordial relationships I have always enjoyed with this company. I can truthfully say that of the group which have participated none has given me greater support and shown greater confidence in me that this company, the Texas Company.

In this particular instance, Colonel Klein of the Texas Company, its chief counsel, said that he felt terribly embarrassed because of the position they had to take; but their interests were so great, their oil interests, not only in the Texas Panhandle but in other parts of Texas where this legislation and litigation which was pending might be used, and their oil interests might be so impaired, that they felt

they could better afford to throw their interest in Texas out the window and get out and try to protect their oil properties. The Texas Company took this position because the legislation or the policy of conservation for which we were striving was diametrically opposed to their best interests, namely, the taking of unlimited quantities of gas to be produced with the oil, the raping of these gas reserves, which was done by the oil operators. The Texas Company, however, was not the worst in the field. In fact, I would say that it is one of the best oil operating companies down there. But the things we were urging for the conservation of this gas, the cementing of the casing and stopping the wastage of this gas by stripping, were all opposed to their position, and therefore they had to take the position they did.

Direct Examination Resumed by Mr. Morgan.

So that the basis of their opposition might be made clear, they explained to me that their position was that this
401 wastage and dissipation of the gas, which would render much of their oil unrecoverable, could not be stopped unless the pipelines were required to purchase gas from all owners. This would have cost us a lot of money and we felt that such cost was unjustified and we had to take an opposite position. Those objections were frankly discussed. Colonel Klein said that he had no quarrel with me at all; that he recognized the position in which I found myself, and there was nothing that I could do. He did not urge me to change my position. He said he hoped there was some way of modifying our course and reaching some agreement which would prevent destroying the protection they were seeking for their oil properties.

Representatives of that company did go down and appear before the committee and defend this feature of prorating, in opposition to our legislative position. A bill was enacted which incorporated the provisions we opposed. We lost in the legislature but finally prevailed in the courts.

(At this point counsel for defendants, in reply to questions of the Examiner, stated that this legislative fight to which the witness referred was in the spring of 1935. There was a four months session of the legislature, and the court fight continued for over a year and was finally decided by the Supreme Court on February 1, 1937, in the case reported in 300 U. S., which has been frequently referred to.)

The total acreage transferred to Texoma about August 21, 1931, was approximately 316,000 acres.

Exhibit 81 is a map which I have caused to be prepared showing the location of this acreage. It shows the principal counties of that portion of the Texas Panhandle embracing the gas and oil development generally known as the Texas Panhandle field. The boundary is according to the Railroad Commission's 1937 conception of the extent of the field and is shown by that heavy black line. The red colored areas represent the lands upon which Texoma acquired gas leases as of August 21, 1931. The date shown on the map is August 1, but it should be August 21. As of August 1 there may have been a few leases which were held for the account of Texoma which were surrendered before August 21; but they did not represent any appreciable quantity of leases.

(EXHIBIT NO. 80 for identification, offered and received in evidence without objection.)

At the time Texoma actually took the legal title to its leases, for which I have already stated it had made its commitments some time before, all of the original participants were not still in the project. As of that date Phillips Petroleum Company and Skelly Oil Company withdrew from the project. Phillips Petroleum Company had made a prior agreement with the Texas Company under which they were permitted to sell their participation to the Texas Company. It seems that Phillips was not entirely satisfied with the negotiations which were developing in connection with the sales contract with the Chicago District Pipeline Company, and made some agreement with the Texas Company in the event they might want to dispose of their participation and get out. The Texas Com-
402 pany advised that if that developed, they would like to have an option or call upon Phillips' interest, and that agreement was reached between the two participants independent of the other owners.

Skelly Oil Company, of which Mr. Skelly was president, expressed a desire to sell their interest in the project and asked me to see if the other participants were interested in acquiring control of their participation before they offered it elsewhere. In fact, the Phillips representatives came to me and expressed a desire to withdraw from the project, and made known their agreement with the Texas Company, and asked me in the capacity in which I was then serving if I would take these matters up with the

interested parties. That I did, and arrangements were made for the acquirement of the Phillips and Skelly interests in the project.

The trouble so far as they were concerned with the rate contract which we had negotiated with Chicago District Pipeline Company was with respect to the contract of July 25, 1931, which is one of the contracts filed with the Federal Power Commission as a part of our rate schedule. It is the contract under which a very large proportion of the pipeline capacity is sold here in Chicago to the Chicago District Pipeline Company, which in turn serves the three distributing companies to which I referred yesterday, whose lines serve the Chicago metropolitan district.

Counsel has asked what was the trouble with the contract so far as Phillips and Skelly were concerned which made them want to withdraw from the project. They stated their objections to me. During these negotiations in working out the terms of the contract of July 25, 1931, with the Chicago District Pipeline Company, there was a violent disagreement between the representatives of Chicago District Pipeline Company on the one hand and the pipeline interests on the other. The disagreements were of such proportions and the negotiations so long and protracted, extending over a period of twelve months and more, that finally one or two representatives of each of the contracting parties were asked to withdraw separate and apart from the remainder of the parties and see if some sort of a compromise could be effected. This was done and the resultant price which was written into this contract was so unsatisfactory to the interests represented by Phillips and Skelly that they felt the earnings possibilities were disproportionate with the risks and hazards involved, and asked me to see if negotiations could be made for disposing of their interests to the others before they took their interests elsewhere in an attempt to sell them.

The point I was trying to make is that our negotiations had failed to result in an agreement, so Chicago District Pipeline Company appointed possibly two representatives to meet with two representatives appointed by the group representing Natural Gas Pipeline Company. I am not sure whether Chicago District had one or two representatives in that conference; but those three or four men met as representatives of the two contracting parties to try to see if some sort of a compromise agreement could be reached to reconcile our differences, and that was done.

The man appointed by Chicago District Pipeline
403 Company was Mr. George F. Mitchell, and perhaps he had an assistant with him or he may not have had. I would prefer not to attempt to name the other representative because I cannot be sure that he had one, and if so, which of the number of men who were assisting him in these contract negotiations it might have been. On the pipeline side were Mr. H. O. Caster, who was at the time associated with Cities Service Company, and Mr. R. W. Gallagher, who was associated with Standard Oil of New Jersey.

I have stated that I succeeded in disposing of Skelly's interest to the other participants, or that I was instrumental in bringing about such a disposition, and that the Texas Company acquired the interest of Phillips Petroleum Company. Those interests were disposed of within less than thirty days after the contract of July 25, 1931. Settlement was made for acquiring their interests on August 21, 1931.

As to the acreage which we had agreed to acquire from those two companies, we acquired their acreage at the same price paid for the acreage of the surviving participants, namely, $45 an acre, and they were reimbursed dollar for dollar for all the cash which they had advanced for the construction of the line and the other expenses incidental to the completion of the project, with interest to the date of their withdrawal. This consideration of $45 an acre was paid to Phillips Petroleum Company and Skelly Oil Company, and subsequently the recipient of the Skelly interests merely stepped into the Skelly shoes, and the recipient of the Phillips interests merely took the Phillips place; but that was all after the consideration was paid. It just tended to increase the participation of the survivors. The Skelly interest was divided among the surviving interests on the basis of their prior participation ratably. In other words, the participation of the Texas Company was increased by having the participation of the Phillips Petroleum Company added to it. It had a greater participation by the participation formerly had of the Phillips Petroleum Company. The participation of the Skelly Oil Company was disposed of to all the remaining participants in proportion to the ownership of those participants as of the time they acquired Skelly's interests.

Back in the summer of 1930 the Standard Oil Company of New Jersey sold a half interest in its participation to

the Southwestern Development Company—that is, half of its interest in the pipeline company—and Southwestern Development Company acquired Standard's entire participation in Texoma Company. I do not have the exact date.

We were not ready to commence producing gas from this acreage and transport it through the pipeline on August 21, 1931, when we acquired the title to the acreage. We had not at that time completed our gathering system, and while that was in the process of being constructed we were not ready to start operations. The physical work on the pipeline was completed August 5, 1931; but before it was put in operation there was the testing of the line, as I explained this morning, and the completing of many odd pieces of work. The equipment in the stations had not been fully tested; but we were able upon the completion of the test of the line to start moving gas through the pipeline.

404 Our first delivery of gas was made to the town of Indianola, Iowa, on September 2, 1931. Our next delivery was on September 24, to the city of Glasco, Kansas, and another little town of Winterset, which is also in Iowa. On October 16, 1931, we made the first delivery of gas to the Chicago District under the contract of July 25, 1931. Prior to that time we had made some small deliveries for the purging of Chicago District's line, the testing of their line, filling their holders with natural gas in lieu of manufactured gas; but the first official delivery under the contract of July 25, 1931, was on October 16, 1931.

The entire project was not then complete and in final form to get on a permanent operating basis. We had a great deal of work yet to do in completing the construction work. I would judge that at that time fully 90% of our field forces were still engaged on construction work, and not more than 10% engaged in the physical operation involved in moving gas from the Panhandle to Chicago. The back fill over the line where the soil had been replaced in the trench over the pipe was fresh filled dirt and was subject to settlement, and after the contractors had moved on and had been paid, it was a part of the company's routine construction work in finishing up the job to come along and see that this back fill was maintained, as after each rain there would be heavy settlements; so there was a period until the end of the year that this work of rounding out and completing the construction work was going on. The banks of the rivers where cut in laying the

submerged line had to be rocked, riprapped with rocks, to prevent cutting of the currents, so we were engaged primarily with the job of completing the construction work and finishing up the odds and ends until the end of 1931.

As to when we got out of the preliminary stages and got on a fairly permanent basis of operation, we selected January 1, 1932, as the date of terminating construction, and on that date stopped charging work of this character to our capital account and started them to charge work of this character to operating expense. The date was obviously somewhat arbitrary. It was selected as a convenient calendar date. We continued to do a great deal of that work right on in 1932, work which could probably have been charged to construction, or to capital account; but we had to make some decision as to the date of completing the construction and starting operations, and selected January 1, 1932, as being an appropriate convenient date for making that change.

At that time we were producing gas from our own leases and supplying three-fourths of the pipeline's requirements from those leases, and one-fourth from gas acquired from the Colorado Interstate Gas Company, which came from the reserves of the Canadian River Gas Company.

We did not know with certainty what quantity of gas we had acquired through the acquisition of the reserves about which I have testified. There was no way of knowing. We tried, in the light of the information available, to estimate the probable amount of gas that we had under our acreage. I remember there were various estimates by geologists familiar with the field, and we felt that a fair average figure for the field would be about eight million cubic feet per acre as the quantity of gas in place.

405 We did know that there was lack of uniformity in the content on an acreage basis in different portions of the field. I tried to make it clear in my statement this morning that while we were fully conscious that there were areas of low porosity, lean and barren areas, we also recognized that there were other areas of high porosity which would be productive of good wells, but often these areas seemed so closely associated as to leave considerable confusion as to what the underground conditions might be. It is entirely possible to have a 90 million well within a distance of two or three miles of a two million well. That led to confusion in our minds as to where our most desirable acreage was going to be, or where best to select it. In retrospect,

as I look at it today, although we were using the best information available then, the results are probably attributable as much to good luck as to good judgment that we turned out with the valuable acreage that we have.

We acquired a little over 1,000 separate leases. Had we kept all of those leases in force beyond the five or ten year primary term of which I spoke in my testimony this morning, it would have been necessary for us to drill on those leases a minimum of 1,000 wells. Some of those leases were so situated and the terms of the leases were such that the implied covenant in the lease would never have made it possible to hold the lease with one well. A thousand wells would have held the leases temporarily but not permanently.

At the time we acquired these leases we knew we would not drill and develop the entire 1,000 leases and produce gas from them.

I have referred to implied covenants. In the standard form of lease that is used for the conveying of mineral rights from the land owner to the lessee or gas operator, there is what the courts have construed to be an implied covenant for adequate development of a lease. It is not possible for the lessee to take and enjoy the privileges of a large block of acreage by the mere drilling of one producing well upon that lease, which would have the effect, in the absence of any specific terms to the contrary, of stpoping all rentals. It is, therefore, the obligation of the lessee to drill that lease diligently, to protect the lease against drainage by offsets, and to otherwise drill and produce the lease as would a prudent operator under those circumstances.

In other words, notwithstanding the fact that the lease contains the language that it should continue in full force and effect for a period of five years, or ten years, or whatever the primary term may happen to be, and as long thereafter as oil or gas is being produced from the premises in paying quantities, varying according to the particular contract, that does not suffice to continue the lease so long as oil or gas is produced, unless it be in reasonable quantity. That is a provision the Texas courts have written in the Texas oil and gas leases which does not appear in the language of the lease itself, and that is what I was talking about when I mentioned implied covenants.

At the time we acquired these leases, or at any time thereafter, it was never our thought that we would drill a

well on each of those leases and a sufficient number of
406 wells on the larger ones so as to produce gas from all of those leases. Our thought was simply that because of the necessity of having an adequate reserve to protect the pipeline, the safe way for us to protect this part of our investment was to acquire sufficient acreage so spread throughout the field that we would be in the end protected against faulty selection of acreage which might be in less productive, less porous parts of the field, and when the story had been written by the records of wells, we would still have sufficient good acreage to provide the pipeline project with adequate reserves of gas. We knew that some of our selections would be bad because the information was not sufficiently complete that we could be sure, and some of the acreage which we thought best has since turned out to be not the best. Some of it has turned out to be barren. Some of the acreage that we thought would be most productive has resulted in dry holes, and some of the acreage we thought would be fairly protected against oil drainage has been subject to oil drainage.

These were the conditions against which we tried to protect ourselves, and our acreage selection and acreage play took all of these factors into account. It was our purpose at the time the total acreage was acquired to select from that acreage and develop and retain a sufficient part thereof to constitute a safe and reasonable reserve to take care of the requirements of the pipeline system. That is what we sought at that time to do, and we have never deviated from that policy.

We knew at that time that a large portion of the total leases, stated in terms of acres, would be discarded and never developed; but we didn't know how much and we didn't know which ones. We were merely exercising our best judgment in the hope that finally we would wind up with an adequate supply of gas, whether it be 200,000 acres, 100,000 acres or 50,000 acres. We didn't know what it would be. We were seeking an adequate supply of gas for the project, and this combing process is one which has gone on continuously in the light of information obtained from day to day, from week to week, and from year to year. As additional wells were drilled, the boundary lines of the field have been changed, the sulphur lines have been changed and the ideas of the geologists with reference to the area of high and low porosity have changed. Now the

information is narrowing down each year as additional wells have been drilled and the control points resulting from this information have reached a point where there is less hazard and less guess today than obviously existed ten years ago.

From my own knowledge and experience in the oil and gas business, the procedure which we followed is not at all dissimilar to the practice then in effect by oil and gas companies, and in effect today. In any new field, when oil and gas is discovered, as it has been down through the Central Illinois basin immediately south of Chicago, vast areas are leased in the light of the best information available. Competitive prices exist, and those prices are paid on very meager information, with a complete knowledge that much of that acreage is going to have to be surrendered; but they can't tell which acreage until drilling has disclosed the more productive parts.

407 *Questions by the Examiner.*

Texoma has been acquiring and combing over these leases ever since August 21, 1931. We have acquired some additional acreage. We have surrendered over half of the original acreage we acquired, and we have in the meantime added other acreage, and we have traded acreage with other producers to try to round out these smaller tracts into suitable drilling units.

We have also consolidated leases so as to minimize the amount of drilling. By consolidation I mean that we have taken a number of tracts, each of which would require development, and validated these consolidated tracts by the drilling of a single well. Validating means curing the lease against further rental payments so that one well holds the lease for Texoma as long as oil or gas is produced in paying quantities.

There have been greater eliminations from our original purchases than from additional leases acquired later. In the original purchases under the terms of our negotiations and the competitive conditions under which we were dealing, and the unwillingness of the companies to let us hand pick and select the acreage which we thought most desirable, we took some acreage which we felt at that time we would immediately release rather than pay rental and taxes on it.

Since August 21, 1931, we have acquired only those selected tracts which were adjoining, nearby or contiguous to acreage already held by Texoma and which would round out our acreage into valuable economic drilling units. That acreage has been carefully selected. We have gone bad on some of it, but for the most part we have been a little more discriminating, due to the fact that we were just picking up small tracts which might be near a proven lease which a well had shown to be good territory. Then we would go in and try to round out our leases at that point.

Direct Examination Resumed by Mr. Morgan.

I know of instances in which other companies have acquired acreage and then released a part of it in the course of their normal and ordinary operations. That is the very ordinary and usual procedure. I had access to the records of the Cities Service Company while I was an officer of that company. I am familiar with their practice and policies and their records, and I have caused to be taken from their records a certain statement. In similar manner I have had access to the records of the United Gas Company and its subsidiaries, and have caused to be taken from their books and records a similar statement. That company operates throughout central south and southwest Texas, Arkansas and Louisiana.

(Document entitled "Gas Acreage Controlled", marked Exhibit No. 82 for identification.)

Exhibit 82 was prepared under my direction. It shows the comparative acreage acquirements, releases, and volumes of gas handled by Texoma Natural Gas Company, Cities Service Gas Company, and United Gas Pipeline Company. In the extreme left-hand vertical column are listed the years to which the figures refer.

408 In the first section of figures the acreage records of Texoma have been shown; and reading across horizontally from 1932 we find in the second vertical column that Texoma held on January 1, 1932, 278,000 acres plus; that during the year 1932 new acquisitions to the extent of 2300 acres were made; that during the year 1932, 39,250.01 acres were surrendered; so that the resultant acreage retained by Texoma as of December 31, 1932, was 241,884.18 acres.

In the second vertical column from the right hand side of Exhibit 82 is shown the total acreage controlled by the company as of December 31, 1932, and that figure does not differ

from the last mentioned figure in this instance. Purely for the sake of comparison, the last vertical column to the right shows the sales of the pipeline system from this acreage, which is 21,334,259 MCF.

As of January 1, 1932, the Cities Service Gas Company held 1,171,521 acres. They acquired during the year 1932, 138,196 acres, and surrendered during that year 221,100 acres, holding on December 31, 1932, 1,088,617 acres. That company also held gas purchase contracts as of December 31, 1932, upon 1,012,306 acres, so that the company either owned or controlled gas reserves of 2,100,923 acres, and had a pipeline requirement from that acreage of 49,269,014 MCF, and this pipeline requirement was the annual withdrawal from that acreage.

The Texoma requirement set down in the last column which I first read, 21 million and so on MCF, is the total pipeline requirements which came from Texoma reserves; so with an outlet of a little more than twice as much as Texoma, we find at the end of 1932 that Cities Service owned almost eight times as many acres of gas reserves as did Texoma.

The Cities Service reserves are not all in the Panhandle, and my guess would be that they have about 70,000 acres in the Panhandle. Counsel states that the figure is 104,000. I will check the quantity and be sure of it.

Cities Service does not rely on the Texas Panhandle as does Texoma. On Exhibit 82 I was referring to its entire gas system and its entire gas rights in the midcontinent field, and these figures are not confined to the Panhandle field as to either Cities Service acreage or pipeline requirements.

As to the United Gas Pipeline Company, it has some producing companies along with its pipeline company, just as Texoma is the producing company for this pipeline. In the year 1932 the United and its affiliated companies held, as of January 1, 1932, 1,117,737 acres. They acquired during that year 7,333 acres, and surrendered during that year 109,657 acres; so that as of December 31, 1932, they held 1,015,413 acres. They held gas purchase contracts as of December 31, 1932, upon 80,306 acres. Therefore, the total acreage owned or controlled was 1,095,719 acres, from which they supplied their pipeline system with 148,183,544 MCF.

That same comparison may be made for the years 1932, 1933, 1934, 1935, 1936, 1937 and 1938. 1938 is not shown

on the figures for Cities Service and the United because those records were not available to me at that time.

409 By "United sales on various bases" I mean that the United Gas Company, as is the case with many companies, does not happen to have a uniform pressure base upon which their measurements are made for sales, and rather than to try to convert those quantities, we merely took from the records those quantities, some of which were on a 4 ounce base and some on a 2 pound base. A 2 pound base and a 4 ounce base is the amount on which the pressures above atmosphere are computed, and no attempt was made to convert those to a common pressure base.

(EXHIBIT NO. 82 for identification, offered and received in evidence over the objections of counsel for each of the two Commissions, to whom the Examiner granted exceptions.)

We deemed it important to the pipeline that it provide itself with an adequate reserve of gas because there were certain disadvantages in being dependent upon other people to drill the wells as they were needed and to operate them so as to get an adequate flow of gas in the pipeline. The experience which we had witnessed in the financial failure of pipelines which had not been adequately supplied with natural gas reserves was one of the strong motivating impulses which caused us to look with unusual care to the securing of adequate reserves.

Through my experience with the Empire Companies in Bartlesville and the experience of Doherty as the principal owner of Cities Service Company, we had very vividly impressed on our memories the experiences through which those companies had passed in trying to maintain adequate reserves of gas behind the pipelines.

The life of the average gas field is not long. Perhaps the two most outstanding fields today are the Monroe and Texas Panhandle fields. In the mid-continent, and by mid-continent I refer to the area of Texas, Oklahoma, Arkansas, Louisiana and Kansas and such general areas through there, we knew that the Cities Service Company had had necessarily to be continually seeking new sources of supply. Most of those fields were the result of oil exploration work. The drilling of an oil well might result in the bringing in of a gas well. Other wells were drilled due to the presence of gas, it being a geological indication that the presence of oil might be found nearby.

As a result of this oil exploration work many new pools were opened up, and the Cities Service Company was continually laying its lines into one field after another as the old fields were exhausted. Many of these fields did not last more than from three to five years.

Perhaps the most alarming experience was that of the Kansas Natural Gas Company which Doherty acquired in 1916. When he acquired this company it was in receivership, serving a good population and with adequate markets, but having no gas. The same was true with respect to the Wichita pipeline, the Quapaw Gas Company, and the Wichita Gas Company, which were also acquired by Doherty. They were all in the same position of being without adequate gas reserves, and the earnings of the companies had declined to the point that the companies were bankrupt.

This experience was one we were trying to ward against in providing ample gas reserves for this project. We also found that the local utility companies in Chicago were perhaps as much concerned, but for different reasons than
410 the owners of the pipeline company with the adequacy of those gas reserves.

In the early days, about 1890, three pipelines were built from the fields of southern Indiana to Chicago, with an expenditure in excess of $10,000,000, to bring natural gas to Chicago. At the time these pipelines were constructed there was every evidence that there was an ample supply of gas to justify the pipeline expenditure; but that supply of gas was so rapidly exhausted within a period of about five years as to cause a tremendous loss to the pipeline company, and placed the distributing companies at a great deal of inconvenience, and it had a detrimental effect upon their public relations because of the character of service they were forced to render during the period of change from manufactured gas to natural gas, and from natural gas back to manufactured gas, all of which required an adjustment of the consumers' appliances and burners.

If possible, I would say that the utilities, as the principal purchasers of the output of this line, were, if anything, more concerned with the adequacy of this supply than the other owners of the pipeline.

Therefore, everything considered, it was our feeling that while there were many, many hazards with which we were to be confronted, the greatest blunder we could possibly subject ourselves to was to put millions of dollars into a

pipeline and develop markets, only to find we were without an adequate supply of gas. It was a matter of very great concern to us to make sure that we had an ample supply. In blocking up this acreage, we were not thinking in terms of acreage, we were thinking of gas.

Exhibit 82 reveals how our people were constantly thinking in terms of reserves. There is no other way of expressing on the record what Cities Service and United are buying and what they are surrendering. They lacked geological reserve reports. Those we didn't have access to; but this is the method of expressing their acreage transactions in trying to keep pace with the exhaustion of their gas reserves. Some of this acreage may be good, some may be bad. Much of it is a disappointment, as indicated by the amount which is being surrendered each year; but they are trying constantly to make replacements and keep a proper reserve behind their pipeline at all times to the point where they feel that service will be assured.

Other purchasers were concerned with the reserves besides the Chicago purchasers. The United Light & Power Company, through its subsidiaries, acquired natural gas for introduction into its distribution systems for Rock Island, Davenport, Moline, Cedar Rapids, Iowa City, Ottumwa, Red Oak, and Shenandoah. They have a number of towns in which they own the gas distribution systems across Iowa and Illinois. They were equally insistent—in fact, they were more insistent than the Chicago utilities—and were even demanding that we write into our contract that we would not have the right to cancel a single lease without first obtaining their consent. They were so concerned with the supply of gas, for fear that we might not be properly diligent in the securing of an adequate supply for the gas line, that they were de-
411 manding that we obtain their approval before surrendering any acreage; but we could not submit to that. The acquiring of adequate reserves was an absolute essential entering into our ability to make contracts for the sale of gas at wholesale to those who were distributors and users of gas.

As a result of the policies which we pursued in the acquiring of our reserves and the consolidation of those reserves, selecting and retaining some and the elimination and surrender of others, we feel now that we have an adequate reserve behind this pipeline. We feel much more content with our reserves today than we did when we had

twice as much acreage. We feel that we have so handled our original purchases and our subsequent transactions that our reserves today offer us an adequate protection for the pipeline so long as the policies of the State with reference to conservation and the permitting of stripping, etc., do not accelerate the rate of withdrawals from the field.

If the rate of withdrawal from the field is accelerated, it is our judgment that we would not be able to continue to produce gas in the Panhandle and transport it to market any longer if we had retained our surrendered acreage than we will from the acreage which we now retain. I think we have gotten it down to the best selected acreage. We are in position now, no matter what takes place, where we will get the pipeline requirements until the supply in the field is exhausted.

The total production from the field is what is going to determine the life of the Texoma properties. You must, of course, take into account all economic factors which have a bearing upon Texoma's ability to stay in or being forced to quit before the last foot of gas has been withdrawn from the field. Whenever it is that we will be brought down to an economic point where we will have to quit is going to be determined by the total production from the field, including that of Texoma, without regard to whether we are going to produce from the acreage we now have or whether we produced from all acreage which we had.

Extra costs would have been involved in producing gas from the surrendered part of the acreage. We would have had the carrying charges, the rentals, the taxes, and the expenses of keeping records on that acreage which was surrendered. In the interest of economy, we have saved a considerable amount of money on that, though I don't know just how much.

We have also saved in the matter of drilling wells. Most of the leases would have expired under their primary terms unless we had drilled wells on the surrendered acreage. On August 21, 1931, most of those leases had a life in their primary term of only a few years, and those would naturally have expired by their own terms and renewal expenses would have been necessary to keep them alive. We would not have been able to produce any more gas if we had drilled a thousand wells than we have from the wells we did drill. The pipeline capacity and the market requirements represent the total needs of the system.

I have referred to the hazards and risks involved in the operation of this project. There are extraordinary
412 and unusual risks involved in projects of this character as compared with an ordinary business. Of course, the oil and gas business is known to be a hazardous, speculative form of business; and of necessity, because of the nature of those hazards, banking institutions and people interested in the lending of funds, necessarily as a matter of protection, are not interested unless those companies can show that their rate of return is commensurate with the hazards which they are assuming.

As to the hazards I have had in mind, I briefly mentioned gas reserves; but so far as hazards are concerned more can be said on that subject.

The vacillating conservation policy of the State of Texas in regard to conservation has much to do with the length of life of this field.

Natural gas competition with other fuels in its principal markets is a hazard which must be reckoned with.

The fluctuating demand for natural gas, due to industrial depressions or economic conditions, is a factor to be reckoned with, regardless of competitive prices at which those other fuels may be sold.

Local gas fields, and by local gas fields I mean gas fields which are discovered in closer proximity to the principal markets than the fields from which the pipeline originates, is one of the elements which the financial sponsors of a pipeline must take into consideration. Those local fields are the ones which are completed after the pipeline is constructed, and that one thing is a hazard which has been the constant fear of the natural gas pipeline industry since its inception. Whether the pipeline be fifty miles long, five hundred, or a thousand, any time that a field is completed nearer the market it has a possibility of completely wrecking the original pipeline.

We have as a consideration the necessity for additional capital expenditures, even after the original pipeline is constructed and reserves are required. The project, I might say, turns sour; the earnings are disappointing. Nevertheless, if the project is to be kept alive and continued in operation, additional capital must be continually poured in or an attempt made to liquidate the property and avoid further losses. The first capital expenditure is not the last. Almost to the last day that the pipeline operates, new money must be continually poured into the

project for drilling wells and other types of expenditure which I will attempt to explain more fully later.

There is always a hazard as to whether you will be confronted with increased operation and maintenance expenses in the future. In a project such as this, where the principal income of the pipeline is contracted for over a long period of years at a fixed price, in terms of a fixed dollar value, there is the possibility of increased operating expenses, labor and material, which may result in a profitable venture turning into one of loss.

Inflation represents a hazard, and that was touched
413 upon quite fully by Dr. Palyi in the early part of the week.

There is a hazard of ever-increasing taxation, and increased regulatory expenses.

Then there is always the unpredictable hazard which represents a loss of earnings from pipeline breaks and failures.

I think each one of those subjects is of such importance that it might be worth while to spend just a little more time in more fully explaining why we consider each of these subjects to represent a hazard and concern to financial sponsors of a long distance high pressure pipeline.

Taking these hazards up one by one, and taking first the hazard involved in the matter of gas reserves, I wish to elaborate some on that point. During this hearing there has been considerable testimony bearing upon the influence of water upon the life of the field. That story has not been fully told. We are trying to keep pace with the water conditions in the field. That is a hazard which we were not able to fully appraise at the time the pipeline was built, and I doubt today if we are able to fully appraise the extent of this hazard.

We do know and we are fully conscious that as the pressure is going down water is appearing in these wells. These wells which were absolutely free of liquid moisture at the times the wells were completed are commencing to show water in many parts of the field. It is most concentrated in the Lefors area. We were hoping that it might be localized and that that was the only point which would be troublesome; but in recent months we have had this appearance of water in other parts of the field. It has become troublesome. The extent to which it may in-

fluence the life of the field in drowning out the reserves is only a matter of speculation. We can only guess. We may be unduly pessimistic, or we may be unduly optimistic. That is something that only the future can tell.

As to the influence of salt from this water intrusion, that is a matter that may have a very, very serious effect upon the abandonment pressure of this field.

Other economic factors may make it possible for us to go below 100 pounds pressure, so far as operating expenses and maintenance and sales prices of the gas to the market outlets might indicate that we could go to lower pressures, and yet, as I say, the formations might be salted up and the pores of the producing sands blocked with salt. It has happened with other fields in the mid-continent, and it is not a new phenomenon which we are looking upon as a ghost. The extent to which it will influence our economic life in the Panhandle is a hazard and is unknown. It has caused us to plug eight wells already.

The protection of our leases against activities of the oil operators is something that we are trying to
414 accomplish by working with the operators and the Railroad Commission, but most of our efforts have been in the nature of litigation since we have been unable to obtain any cooperation from the State in the direction of conservation.

Everything that has been attempted in the way of unit development or through cooperative methods which have been used in other places in the United States apparently have not taken root in the Texas Panhandle field. Probably the reason is that there has been such a vast quantity of gas which is out there in the barren plateau plains of Texas, remote from any big markets. If the field were more closely located to the big centers of population and big industries, I don't care whether it was Texas or whatever the State might be, an effort would be made to conserve that natural resource; but in Texas it has not received the same attention it would receive under different geographic conditions.

Therefore, that is a hazard that is ever in front of us. Texas has never looked kindly upon foreign corporations coming into that State, and these pipelines, for the most part, are taking a Texas natural resource to Chicago, Denver, Omaha, Kansas City, and foreign markets for the

benefit and comport and convenience of people outside the State of Texas, and conservation does not receive the same careful consideration as it would if that gas were being marketed within the boundaries of Texas.

This is not said in any attempt to be unnecessarily critical; but these are the facts, and the records of the litigation which has followed the development of that field will bear out the statement that Texas has completely disregarded the conservation of a valuable natural resource.

To date, in spite of all our efforts to provide the pipeline with adequate reserves and to protect those reserves by drilling and seeing that the leases are properly protected against drainage, and by the development of our markets to the best of our ability, only 40% of the gas withdrawn from under Texoma's leases has been produced through the wells of Texoma, the other 60% having been lost through drainage.

So as we go down through the years, in looking to the future requirements of this pipeline, we are constantly confronted with that hazard, as to whether we will be able fully to protect the pipeline with its requirements from this acreage. We think and we hope we will. As to whether we can or not is a matter largely dependent upon the way in which the State permits the oil operators, the gasoline plant and carbon black operators, to withdraw the gas, and as to whether it may be stripped for gasoline, as it was for two years, and the residue blown to the air.

I have heretofore mentioned proration and the efforts of the State to enforce statutes and regulations requiring us to buy gas from others, notwithstanding the fact that we had invested our money in our own reserves. That confronts us as a hazard or a risk involving our business. It is a very great hazard. To date we have been able to forestall the efforts of the State to bring about legalized proration of production in the field. This attempt on the part of the State I touched upon previously this morning.

As these pipelines have undertaken the financial risks and responsibilities of creating markets, the State has attempted through legislation and through the orders of its regulatory commission, the Railroad Commission, to force the pipeline companies to extend their lines over

the field and purchase from all producers ratably in order that they may have an outlet for their gas and share in the pipeline's markets.

I have tried to make it clear why we felt, before we ever built the pipeline or entered the field, that this would be a dangerous policy for the company to follow. We felt that it would be perhaps not suicidal, but it would materially increase the hazards to which we would be subjected if we were forced to depend for our supply upon purchased gas.

Therefore, having gone in and expended our money and provided ourselves with adequate reserves, and having injured none, the gas being withdrawn from under our leases and not drained from others, we have not felt kindly disposed to the State's efforts to force us to buy gas from others and share our markets to the economic disadvantage of having to see more gas drained from under our leases and possibly be produced through neighboring wells, and force us to purchase that gas and provide it with a market through our pipeline. That is a fight that has not yet ended.

It would naturally cost us money, aside from the gas drained out from under our leases, if we were forced to purchase that gas and provide it with a market through our pipeline. We would not be able to fully develop or take advantage of our own gas reserves, and we would have to pay out new money for gas which we would purchase from others. We would probably have to pay for that gas around 4½ cents per MCF at the mouth of the well.

This possibility of having to purchase gas is one of the hazards that we have not yet licked. Some of these things which loomed up as dangerous hazards at the time we were making the initial investment have reached the point where we feel somewhat reconciled to the fact that they are not going to be as bad as they first appeared; but in the meantime others have appeared to take their place, some of which look even more hazardous than the original ones with which we were concerned. This question of having to buy gas is one that we have fought through the courts and each time to date we have been successful in maintaining the soundness of our position; but the legislature of Texas, which adjourned just last week, I think it was June 21, experienced another bitter fight

between the opponents and proponents of this activity on the part of the State to try to force the pipelines to buy gas.

Without trying to quote the legal decisions, the Federal Courts have made perfectly clear, we think, that there is possibly a way in which the State can so pass regu-
416 latory laws as to finally force the pipelines to buy gas. To date, however, the legislature has not been able to pass such a valid law, and the orders of the Commission in their attempt to force by one means or another the purchase of gas have failed. These orders have all been stricken down or withdrawn by the Commission after a hearing in the Federal Court. (Objection by Commission Counsel to foregoing testimony overruled.)

In the recent session of the legislature the bill that was aimed to accomplish the desired result passed the Senate and was finally defeated in the House. It is not my view that the matter will rest there. The proponents of the measure have indicated that they expect to continue the fight, and there has seldom been a regular or special session of the Texas Legislature that this agitation has not been one of the paramount issues.

There is a risk or hazard involved in the situation that we succeeded in getting behind this pipeline the reserves of Canadian River Gas Company to the extent of 25% of our pipeline's requirements. While that is a vast reserve, the pipelines of the Red River Gas Company, the Colorado Interstate, and, I think, the South Plains Pipeline Company, all have a prior call on the gas from this reserve ahead of Natural Gas Pipeline Company's contract for 25% of its requirements to be furnished by the Colorado Interstate.

As the pressures decline and the drilling of these wells becomes less profitable under that contract, and under the contracts for reserve requirements of these pipelines which have prior call to ours, there is the uncertainty as to whether Colorado Interstate will be interested in continuing to supply 25% of this company's requirements, and, if not, in what year that might occur.

If during the course of our project's life they were to serve notice on us that they would no longer furnish us that 25%, we would have to get it from our own acreage, and that would naturally require the drilling of additional

wells to those we have to drill to get ¾ of our requirements.

(Document consisting of Agreement between Canadian River Gas Company and Colorado Interstate Gas Company, dated January 3, 1928, marked Exhibit No. 83 for identification.)

Exhibit 83 is a true copy of the agreement between the Canadian River Gas Company and the Colorado Interstate Gas Company. It is a photostatic copy of a conformed certified copy which we have in our files.

(EXHIBIT NO. 83 for identification, offered and received in evidence, without objection.

Contract between Colorado Interstate Gas Company and Natural Gas Pipeline Company of America, which is on file with the Federal Power Commission, incorporated in the record by reference.)

I wish to add to what I have said about the vacillating policies of the State of Texas as one of the hazards to which I have referred. This so-called vacillating policy on the part of the State of Texas dates back to October 12, 1931, which was in that preliminary period or that twilight zone of completing our construction work and getting started with the operation of this pipeline, so that it is a difficulty with which we have been confronted since the pipeline has been completed and placed in operation.

417 I would suggest for the record, rather than to outline the details of each of these activities on the part of the State and the Railroad Commission, we merely refer to the first of them as the "Common Purchaser Act," which was effective October 12, 1931, and was enjoined by Texoma on November 5, 1931, and on June 8, 1932, was permanently enjoined by a three-judge Federal Court.

Following that we had the attempt of the Commission, on September 6, 1932, to force proration through what was termed as a "shut-down order." This order called for complete closing down in certain areas of the producing wells and limiting others to 4% of the open flow. It was for the purpose of forcing the pipeline companies to take through purchases a part of their requirements from areas which were not then served by pipelines. Texoma and Cities Service secured temporary restraining orders on September 17, 1932, and on December 23, 1932,

a three-judge Federal Court declared the Commission's shut-down order void and enjoined its enforcement.

That was followed on November 12, 1932, by a legislative act entitled "The Market Demand Statute". On December 30, 1932, the Commission issued an order under this statute restricting gas production to the pipeline market requirements for light and fuel, and this order was based upon a production unit of 160 acres per well. There were other provisions of the order which I believe are not relevant. On January 1, 1933, Texoma secured a temporary restraining order, and on June 22, 1933, a three-judge court declared the Commission's market demand order void.

Every attempt of the Railroad Commission up to January, 1933, had failed to force the pipeline companies to purchase gas. Since it did not appear that a valid order could be drawn or enforced, the Railroad Commission then started issuing permits for the stripping of dry gas, the effect of which was to permit the gasoline to be extracted from the dry gas and the wasteful dissipation of the residue gas to the air.

Naturally, if this practice continued, the reserve upon which the pipeline companies were dependent for their supply would be rapidly dissipated and their projects doomed to failure, and yet they were not willing to compromise their position and purchase gas in an attempt to eliminate stripping.

That began in January, 1933. The first permit was issued to Hagy; Harrington & Marsh, a firm of producers in the Panhandle who had assisted and sponsored the prior legislation in trying to force the pipeline companies to purchase gas. After this first permit was issued to Hagy, Harrington & Marsh, which would permit the stripping of the gasoline from the dry gas and the wasting of the residue to the air, by March 7, 1933, 34 companies had made similar applications, and by July, 1933, 36 such permits had been issued covering 320 wells with an aggregate open flow of three and a half billion cubic feet.

That was followed on September 1, 1933, by the Texas legislative act known as the "Sour Gas Act," but the effect of which applied to both sweet and sour gas alike. It started out as a statute authorizing the stripping of sour gas, and afterwards by amendment it was changed to include all gas, including sweet gas, but it continued to carry the name "Sour Gas Act".

This statute was attacked in March, 1934, by several
418 of the royalty owners who sought to enjoin six of those companies which had received permits for stripping gasoline and wasting the residue to the air, and their suit was to enjoin those companies from the operation of their stripping plants. On July 27, 1934, Federal Judge Kennerly sustained the defendants and dismissed the injunctions. On March 28, 1935, a three-judge court sustained Judge Kennerly's decision, and stripping operations were continued at an accelerated rate.

I think it is not difficult to visualize the position in which the pipelines then found themselves, with the State having passed an act legalizing the stripping of dry gas and wasting the residue to the air and that act having been sustained by the Federal Courts. It looked like the life of the field was doomed to be extremely short. However, public sentiment was so strong against the wasteful dissipation of these natural resources that the stories were carried from one end of the continent to the other, so that it caused considerable commotion in Washington, in Congressional circles. The Department of the Interior was very much concerned with the way the State of Texas had legalized the wasteful dissipation of natural gas.

Sentiment was so strong that in May, 1935, the Texas Legislature passed House Bill 266, which repealed stripping and limited the use of sweet gas for pipeline purposes. However, under the guise of protecting correlative rights and eliminating waste, the Commission entered an order for the proration of gas for pipeline purposes, based upon 50% open flow and 50% acreage factors for determining the amount to be allocated to each well.

On September 19, 1935, Texoma obtained a temporary injunction against this order, and on March 31, 1936, a three-judge Federal Court declared the Commission's order void. On May 28, 1936, the State appealed the three-judge decision to the United States Supreme Court, and on February 1, 1937, the Supreme Court sustained the lower court's decision.

On May 20, 1937, the Texas Legislature passed Senate Bill 407, which was generally known as the "Sour Gas Law". This law limited the use of sour gas to carbon black and fixed the amount which could be utilized to 750,000,000 cubic feet per day as a limit. On July 23, 1938 the Federal Court sustained the validity of this act.

On November 27, 1937, the Railroad Commission issued

a proration order for prorating sweet gas in the East Panhandle field under House Bill 266. The East Field, I think, has already been sufficiently defined in this record as being that portion of the Texas Panhandle field east of a north and south line passing approximately through the town of Lefors. It is an arbitrary designation of an area by the Railroad Commission for that part of the southeastern portion of the field as contrasted with that to the north and west of that dividing line, which the Commission has termed the West field.

The Consolidated Gas Utilities Corporation sought to restrain the Commission's enforcement of the order in the East Panhandle Field, and this was followed by cross
419 action on the part of the State to enjoin the Consolidated Company from violating its orders. The case was removed to the Federal Court and remanded to the State court, but it was never heard.

On December 16, 1938, the Commission issued an order applicable to the West field in effect the same as that which had been applied to the East field, except for minor details, and stated in its order that it was to become effective January 1, 1939, and was for the purpose of stopping drainage. The effect of the order was to prorate gas in the West Panhandle field, which would cause Texoma to purchase an appreciable percentage of its pipeline requirements.

On December 23, 1938, Texoma obtained a temporary restraining order, which was followed on January 6, 1939, by a three-judge decision which held that House Bill 266 did not authorize the Commission to enter a proration order based on drainage.

I have already previously referred to the recent legislative activity during the session which adjourned on June 21. It was on May 2, 1939, that the Texas Senate passed a statute authorizing the Commission to prorate sweet gas production if they found that by so doing it would retard, prevent or minimize waste and drainage. This bill as defeated in the House on June 1.

The intention of those who have sponsored this fight, the avowed intention, is still to try to pass some such legislation. As to whether they will be successful, we can only speculate. If they are successful, it will naturally force Texoma into a most hazardous and uneconomic position of having to produce less of its gas from its own

reserves and purchase, in effect, its own gas coming from under its own leases through surrounding wells of others. It will have to build pipelines out to those wells and install meters. I would say that that is a very, very strong hazard that has been ever present, and there is no prospect to date that we are going to be free of it.

(At this point counsel for defendants, at the request of the Examiner, pointed out Paragraphs 1, 3, and 22 of Exhibit No. 83 as forming the basis of the prior call on the reserves of Canadian River Gas Company ahead of Natural Gas Pipeline Company of America's contract for 25% of its requirements to be received from Colorado Interstate Gas Company, as testified to by defendants' witness Floyd C. Brown at pages 2146 and 2147 of the record.)

(June 30, 1939)

The third hazard or risk which I enumerated is that of natural gas competition with other fuels, and the fourth risk is that of fluctuating demands for natural gas. They are somewhat related and may be discussed together.

The competition of coal, fuel oil and other fuels is an influence which creates a hazard upon the earnings of the pipeline company. A pipeline transporting gas from fields 950 miles distant from the markets, such as Natural Gas Pipeline Company, cannot exist alone upon the revenue from the sale of domestic gas. It must rely upon the revenue which it derives from the sale of industrial gas to round out its earnings; and conversely, such a pipeline
420 could not prosper through the sale alone of industrial gas.

It is through the revenue derived from industrial sales that the pipeline is able to maintain reasonable domestic rates; and to the extent that the revenue from the sale of industrial gas fluctuates, or to the extent that there is lack of uniformity over a period of years in this revenue, the owners of a pipeline company are unable to forecast with any degree of definiteness what the pipeline earnings will be.

Industrial consumers of natural gas are not as a usual thing inclined to rely upon getting their fuel requirements from a pipeline unless there is a possibility of obtaining continuity of service. This pipeline cannot offer such service for two reasons. First of all, it is definitely committed by policy and contract to give preferred service to

the domestic consumers. By this I mean to the distributors, who in turn serve directly the ultimate consumers. Secondly, it would be impossible to guarantee continuous service to industrial consumers because of the physical conditions under which gas is transported. The pipeline is subject to interruptions and breaks, so that it would not be possible for an industry to contract for a positive assured supply of gas from such a line as is serving Chicago.

Therefore, the industry, if interested at all in natural gas, must be on something better than a straight competitive b. t. u. basis, because if they convert their plant to natural gas and the nature of the operation of that industry is such that they have furnaces, such as a glass plant, or blast furnaces, or any type of furnace that is damaged because of sudden curtailment of fuel supply, or if the nature of the industry or factory consuming this fuel is such that they are under contract to supply the output of their plant under specified time limits, etc., they must know definitely that this fuel supply is going to be continuous.

Therefore, to offset their inability to obtain a definite, assured, continuous supply of natural gas, they must provide standby equipment, either by storage of fuel oil or arrange for a quick transfer to powdered coal, or some other type of fuel which can be injected into the same furnace which is designed to operate on natural gas.

So natural gas, which is sold by this company on an interruptible basis to these industries, is not in a position to compete on a straight B. t. u. basis, unless the natural gas should have, because of its characteristics, some superior value to that particular industry. In boiler plants and furnaces of that type gas does not possess such superior qualities as to demand a premium, or such a premium as to offset these other features which tend to detract from its value.

Again, the industry is subject to fluctuating economic conditions, and even though it were possible for the pipeline to offer a continuous non-interruptible supply, the industry would not be willing, and never is willing, to contract with the pipeline upon a firm basis of take or pay; and obviously, they are only interested in taking that part of their requirements which serves to meet their needs.

421 An industry must be free temporarily to suspend, curtail or completely shut down its plant if the prod-

uct it is manufacturing is not in demand, due to recessions, or whatever the conditions may be. If it is necessary for them to suspend, curtail or completely discontinue operations, naturally they are not interested in the supply of gas.

This gas moving through the pipelines cannot be stored. There is no practical means of storing natural gas. It moves in a continuous stream from the wells through the gathering systems to the compressor stations and through the pipelines to the burners of the industry consuming it. This fluctuating demand, regulated only by the desire and demand of the industry, has to be met by the pipeline standing by as a shock absorber to meet those fluctuating requirements.

Therefore, the earnings derived by a pipeline, such as Natural Gas Pipeline Company, from the sale of natural gas are not uniform. In 1938 we experienced a decline in the sale of natural gas for industrial purposes as compared with 1937, a decline or decrease of over $700,000. It was unanticipated. There was no way of forecasting that the industries would not consume as much or more in 1938 than they did in 1937.

So this represents one of the fluctuating sources of revenue which a pipeline is unable to anticipate, and yet it must be prepared at all times to meet the requirements of that industry through the drilling of wells and the maintenance of service in its pipeline; otherwise, the value of its fuel would be even less than under the conditions which I have already outlined.

Questions by the Examiner.

As to whether we lost industrial customers or whether our industrial customers simply took less gas, in 1938 the loss in revenue was attributable largely to reduced consumption. There were some few industries which suspended operations, or may have gone to some other fuel; but for the most part it was, in 1938, the result of reduced operations, lessening consumption.

The point you have raised, however, is an important one. These contracts with industrial consumers, because of the fluctuating nature of their requirements, are really optional contracts. We can't ask them to take or pay, or to pay a demand charge if they fail to take, because, after all, the

gas has to meet these other competitions. If it has some superior utilization value which will enable you to demand a premium for it, then in some few industries you might get that industry to pay a demand charge; and it may suspend and only pay the demand charge and not pay the commodity charge if they are unable to take gas due to industrial conditions forcing them to shut their plant down. Under those conditions they might continue to pay the demand charge; but that is not the usual thing. So an industry, in buying natural gas, in effect buys upon an option.

Here is another thing that influences the volume of gas sold by the pipeline company to that industry. Sel-
422 dom, if ever, will they contract for their total fuel requirements. There is practically no way of depriving them of the privilege or right to use some other fuel such as oil or powdered coal in their plant, if, due to the change in the market price of these competing fuels, they can get another fuel at a lower price. We cannot insist upon the exclusive use of our fuel, because we are not in position to supply their firm total requirements. That forces us to permit them the flexibility of bringing in other fuels, not only as a standby, but in the event of a lower price to take these other fuels in lieu of gas.

So the pipeline is more or less of a shock absorber, and must do the best it can in deriving revenue from the sale of industrial gas on a strictly interruptible basis.

As to the average relative importance of our industrial sales against the total business of the company, industrial sales in 1937 were roughly three million seven out of a total gross of approximately fifteen million dollars. In 1938 the total revenue to the pipeline company decreased approximately $1,300,000, and of that amount over $700,000 was attributable to loss of revenue from the sale of industrial gas.

Cross-Examination Interposed by Mr. Booth.

When I speak of the sales of gas to industrial consumers I am referring to the separate contracts which the Chicago District or Natural Gas Pipeline Company has with industrial consumers, and not the sales that the Peoples Gas Light & Coke Company or the Public Service or Western United may have. To make that a little more

clear, I would like to explain that under the base contract of July 25, 1931, with the Chicago District Pipeline Company, the supply of gas is sold for domestic use primarily. That amounts to a quantity for the domestic use of 120,000,000 cubic feet per day. The distributing companies receiving this supply of gas from the Chicago District Pipeline Company are privileged to sell it in turn to such shops or industries as are known in the trade as commercial customers. They may be restaurants, barber shops, beauty parlors, bakeries, hotels for hot water heating in the summer time, and other selected small consumers who are really different than a domestic consumer but of such a commercial character that they can afford to pay rates approximating the domestic rates. They do not fall in the category of the class which I have chosen to call, and the industry thinks of, as industrial consumers.

The term industrial consumer as I am using it here refers to such companies as the steel companies, power plants, and such plants as American Can, Libby, Owens & Ford, Owens-Illinois Glass, and industries of that type, which are not known in the trade as commercial consumers.

Direct Examination Resumed by Mr. Morgan.

The Peoples and the other distributing utilities ordinarily take the gas and supply the gas which they buy for industrial consumers through the Chicago District
423 Pipeline Company, or if farther down the pipeline, directly buy from our pipeline company; but the quantity of gas that they take from us for that purpose is dependent upon what the industry wants and what the industry being supplied requires. We are just omitting the routine of the Chicago District Pipeline Company, which in turn distributes to the three distributors, and going to the industry because industry constitutes the ultimate demand for gas. When they do not require it, those who directly supply it do not require it of us.

I would like to amplify that in order that my prior statement may be perfectly clear. When I have commented upon sales to industrial consumers, I intend that my remarks should refer to pipeline sales of Natural Gas Pipeline Company to Chicago District Pipeline Company under special contracts for resale by either the Chicago District or the distributing companies direct to the industrial consumers.

There are a few instances where the Natural Gas Pipeline Company sells direct to industrial consumers. In Illinois we have one customer, the New Jersey Zinc Company. In Iowa we have one consumer that comes to my mind which we term an industrial consumer, which is a sand drying plant. So when I have spoken of sales to industrial consumers, my comments are intended to refer to the Natural Gas Pipeline Company's special contracts with the Chicago District or other utilities for resale to the industrial consumers. My remarks would also apply to those few industrial consumers to whom we sell direct.

Speaking of this fluctuating demand, on June 10 the Division of Department Reports at the State Capitol at Springfield reported that sales to industrial consumers under interruptible service rates in the State during 1938 decreased 18% under 1937. I only mention that figure as being indicative of the condition which I have described as one which applied to Natural Gas Pipeline Company in 1938, and to show that that condition was not peculiar to our own situation.

Questions by the Examiner.

The 18% refers to the sale of natural gas to industrial consumers served on an interruptible supply basis in Illinois in 1938 by our company and other companies. Our company's sales would undoubtedly be included in there. Our company's sales would include the utilities which distribute our gas, and I presume that the term "and other companies" would mean other main transmission pipeline companies which also come into the State and make industrial sales. I have no way of knowing the extent to which this bureau has included sales by other pipeline companies; but since this report was issued by the State, covering state-wide activities, I naturally assume that it would include them all.

Cross-Examination Interposed by Mr. Slaff.

The date of that report was June 10, 1939. It was just the bulletin which was issued by this department for release to the press. No special point is made of it, except to show that the trend of industrial conditions in 1938, as shown by this bulletin for the statewide conditions, was not different from those which we experienced.

424

Direct Examination Resumed by Mr. Morgan.

During the year 1937 our interruptible sales were $3,785,000. The corresponding figure for 1938 was, roughly, $3,069,000, a difference of something over $700,000.

There is one other factor in the offing which may have a very material effect upon the revenues of this pipeline company as derived from the sale of industrial gas, and that is the result of a bill which has been introduced in Congress upon the recommendation of the President following a report to the President by a specially appointed committee. The bill, which is known as Senate Bill 19, recommends the creation of a natural resource board to formulate plans for conservation of natural resources. It is the recommendation of this committee and the intent of this bill that natural gas should be replaced by coal and lower forms of fuel. It is an emergency defense measure. I mean as industrial fuel. The passage or enactment of such legislation would, for the duration of the period deemed advisable by the committee or department charged with the enforcement of such an act, naturally have a very detrimental effect by lessening the revenue of the pipeline company from its sale of industrial gas.

Question by the Examiner.

As to what the report stated as the basis for such recommendation, I think it was more a conservation measure than anything else.

(Mr. Morgan here commented that Senate Bill 19 does not apply merely to gas but applies to all the natural resources devoted to fuel and power, namely, coal, oil, natural gas and water power, and the underlying ostensible object was to control the use of those fuels, requiring the use of the lower order of fuels and reserving the higher order of fuels and power resources for more important uses; that it is probably related to the agitation going on in Congress and many of the legislatures to require and bring about conditions that would require the use of coal for industrial purposes, on the ground that the use of other fuels might be affecting labor conditions in the coal mines, or railroad revenues for transporting coal, and things of that sort.)

Direct Examination Resumed by Mr. Morgan.

There is one other factor that has an important bearing upon the use of natural gas by these industries, and that is in addition to the economic conditions or those factors which may influence generally one or more industries; that is, that although you may have a depressed condition in the automotive industry, nevertheless it does not necessarily follow that all other industries will be depressed during that particular time. In the same way we may have a vast over-production of crude oil at a time when other industries are prospering, and we will experience very severe depression or depressed set of conditions in the oil industry, with the result that the crude oil and fuel oil prices may recede to very, very low levels. When this situation arises it naturally has its effect upon natural gas.

425 I do not mean to imply that if crude oil today were cut to 40 cents per barrel in the field that we would immediately feel the influence of that reduction in price of crude oil and the resultant effect on fuel oil in our industrial markets; but it does have its influence and those industries which are equipped to burn fuel oil do take advantage of such opportunities when the swings in prices come.

In looking back over the fluctuating prices of fuel oil, we see some wide swings from 1929 to 1939 in the mid-continent field price of crude oil. Taking the entire average for light, heavy and all grades of crude oil in the midcontenint field—and these are public posted prices—the average price in 1929 was $1.36; in 1930 it was $1.22; and in 1931 it dropped to 60 cents, less than 50% of the field price in 1929. In 1932 it came back up to 84 cents. in 1933 it dropped to 62 cents. In 1934 it came back to $1.00. It was $1.00 in 1935; $1.10 in 1936; $1.21 in 1937; and $1.17 in 1938. Looking back to 1931, although the average was 60 cents a barrel for the year, a low price was reached in June and July. In June the price per barrel of crude oil was 33 cents, and in July 27 cents. In May, 1933, it reached a low of 28 cents. These prices are indicative of the swings which influence competitive values of fuel oil.

Another thing I would like to make clear in order that the statement may not appear exaggerated is that the

price of fuel oil does not always bear the same fixed relation to the price of crude oil. You may have periods when the fuel oil, after removing the gasoline, kerosene, lubricating oil, and other derivatives, may still sell for almost the same as the crude oil; but as a usual thing, when you have an over-production of crude oil which depresses the market price of crude oil, it only naturally follows that your price of fuel oil also recedes, because it becomes a drug on the market. You cannot have an over-production of crude oil for very long without having your market flooded with cheap fuel oil.

As to whether we are confronted with any immediate situation of that character at this time, we have such a situation here in the near vicinity of Chicago, Southern Illinois, and over in Central Michigan. We have seen the central and southern Illinois crude oil fields increase their production in a period of two years from almost nothing, until today the production in that field exceeds 225,000 barrels per day. The market price has receded and the quoted price, unless it has changed within recent days and has not come to my attention, today is $1.15 per barrel; but this posted price is not the price at which that oil is moving in most cases. In many cases the price as what the producer can obtain if he is not provided with a pipeline. Much oil is actually selling today in that field for 30 cents per barrel, although the posted price represents the market price posted by the larger companies.

That crude oil is moving in big quantities into these Chicago refineries, and that cheap crude oil when refined will result in vast quantities of fuel oil, which, naturally, will seek its markets near at hand. Under present refining methods, 225,000 barrels of crude oil would probably result in 100,000 barrels of fuel oil.

426 The contracts which I have termed contracts for interruptible sales give the consumer the absolute right to decline to take any gas on certain days, and likewise leave us the liberty, when we need the capacity for our domestic requirements, to decline to deliver them any gas.

The contracts between Natural Gas Pipeline Company and Chicago District Pipeline Company, and the contracts in turn with the industries, are what I would term more nearly desire contracts, and by desire I mean that there is no obligation upon the Pipeline Company to deliver any of the capacity of its line or such reduced capacity as it

may have in the event of a break or lessened ability to deliver if the Pipeline Company elects to serve that gas to the domestic consumers, or for any other reason desires to reduce the delivery to the industrial consumer, it is privileged to do so. The industry in turn has the same flexibility.

If the Pipeline Company were in position to offer firm, uninterruptible service, it naturally could demand more for its gas and insist upon the industry's entering into some firmer type of contract; but our inability to render that service of necessity leaves the industry even greater flexibility because they do not need to take our gas. They can go to other fuels. They can just tune up to the crude oil burner that week or that month.

Questions by the Examiner.

I think I would say that this 225,000 barrels coming in from southern or central Illinois is presently a serious situation, and the extent to which that production may ultimately go is quite unknown. I would not attempt to state the number of wells that are today being drilled and the new fields which are being explored through wildcat development. Wildcat is a term that is used for wells that are drilled remote from production, where they are attempting to determine or locate new fields. The volume of the oil being produced, however, is having such an influence upon the price structure throughout the entire United States that it is viewed by the industry with alarm, and attempts have been made by the major companies to influence legislation in Springfield to bring about conservation or to prorate the production so as to hold back this flush production, which is apt to be wastefully utilized.

To date the legislature in Springfield has not seen fit to pass conservation laws or to try to prorate the production of the State, and, if it is admissible, I would like to state that the expression of Lieutenant Governor Stelle has been to the effect that the State of Illinois has not heretofore enjoyed the revenue and prosperity from oil field production in large quantities, and it was his feeling that if there was an over-production of crude oil, some of the States older in terms of oil production should be the ones to retard their production materially and not ask that the State of Illinois hold back its fresh flush fields; that

Illinois is behind in its opportunity to produce and
427 enjoy the revenues, and that he was not favorable to the passage of legislation which would restrict the output of these fields. So to date there has been no legislation passed to curb the production of fields or to circumscribe the amount of drilling which is being done.

I think my statement might have been misleading to some extent. I do not wish to imply that the 225,000 barrels is all moving into the Chicago district. It isn't. Many of these refineries in Chicago, however, which were formerly operating upon crude oil transported from distant fields in Oklahoma, Kansas and Texas, are now curtailing their takes from those fields and obtaining their requirements from the nearby local fields, and the amount of this oil which is moving into the Chicago district, by which I mean Chicago and the refineries around Indiana Harbor and the Gary basin, from these Illinois pools I do not know, and I doubt if it is a determinable quantity.

I happen to know enough of the operation of some of these refineries to know that is taking place; but the amount of it I do not know. It is only natural, however, that these refineries would avail themselves of the cheap crude and the lessened transportation cost to get it into their plants, if possible.

Direct Examination Resumed by Mr. Morgan.

The fifth risk or hazard which we have confronting us, namely, the possibility of discovering gas fields nearer to our market and the results should such possibilities materialize, was touched upon rather briefly yesterday, and it seems to me to follow quite logically our discussion of these Illinois pools.

A pipeline transporting natural gas from the Texas Panhandle field, a distance of 950 miles, must of necessity underwrite the risks which it assumes when it tr nsports gas those distances, the risks against local gas fields being discovered in closer proximity to the markets.

It is quite obvious that if gas fields of any size were to be opened up in these southern Illinois oil pools, where so much drilling and wildcat development is taking place in the exploration for oil, naturally, the Chicago market would be attractive. If gas should come into these markets, then the only thing that Natural Gas Pipeline Com-

pany could do would be to meet that destructive competition from these local companies, with lesser pipeline investment, transportation and operating expenses or suffer the loss of its business. In either event, it would mean virtual destruction of the pipeline.

We have a similar situation in central Michigan; but, fortunately for Natural Gas Pipeline Company, neither of those fields to date has produced any appreciable amount of natural gas.

There is a small gas field opened in southern Illinois; but to date it has not been sufficient to attract attention or
428 cause a pipeline to be built out of the field except to nearby local markets. There is not sufficient gas to justify a big pipeline out of the field; but experience has shown that where there are large accumulations of oil, there are very frequently large accumulations of gas. It has happened in our Texas Panhandle field, and it has happened in practically all fields in the midcontinent that where oil has been discovered, gas has been found in formations nearby. There may not be any gas discovered in that field. However, some deep tests are being drilled and there is a possibility that gas in appreciable quantities may be discovered, if not in the present Illinois field, in the Michigan field, or perhaps in others.

There is what is termed in the industry a big land leasing play now taking place in the Forest City basin. It is a large geological basin extending from near St. Joe, Missouri, north to Omaha, Nebraska, and in that big geological basin the major companies are leasing in all directions, taking oil and gas leases. To date no development has taken place; but the fact that the major oil companies are interested in that play indicates that it is not a geological or land-selling promotion. They think enough of it that they are putting real money in there and buying leases.

That area may not produce any oil, it may not produce any gas, and yet it is one of those potential hazards with which the pipeline is confronted, and which means the virtual destruction of the pipeline if a big field comes in. It simply means the gas from those fields is going to seek these markets.

(Map entitled "Rand McNally, Loose Leaf Outline Map, United States" with certain gas fields, namely, the Texas Panhandle field, the Illinois field, and the Michigan field, pointed out and lines drawn showing the distances from

those fields to Chicago, marked Exhibit 84 for identification.)

In response to a statement by Mr. Booth in which he took exception to my statement that if natural gas were produced in large quantities in the Illinois pool it would result in the destruction of Natural Gas Pipeline Company, and his statement that the record clearly shows we have a long term contract with Chicago District Pipeline Company which is guaranteed by Peoples Gas Light & Coke Company, and that under the Illinois Act and the Natural Gas Act no new line can be constructed without the consent of either the State or the Federal regulatory authorities, I would like to offer this observation:

In the first place, there is no prohibition against pipelines moving into the Indiana territory and serving Indiana industries with gas which were originally served with gas by Natural Gas Pipeline Company. That is outside the jurisdiction of the Illinois Commerce Commission, but it would fall under the jurisdiction of the Natural Gas Act, being interstate. On the other hand, those industries in Illinois utilizing gas from this pipeline could derive gas from an intrastate line which would fall outside the jurisdiction of the Natural Gas Act. It would be under the jurisdiction of the Illinois Commission, and we would hope to derive the protection of the Illinois Commerce Commission.

429 On the other hand, if any part of the revenue from this industrial sale of gas is lost to this pipeline, the pipeline cannot survive upon that guaranteed base load contract of July 25, 1931. The revenue provided by that contract does not enable this company to live. It must have its industrial revenue. The guarantee in that contract is for only a part of our consumption. We have a contract of guarantee on these other industrial contracts; but they are very short term contracts, the most of which expire December 31 of this year, and some of which are being currently extended. Any time the industries concerned under those contracts cut off our gas and bought cheaper gas, there would be nothing to guarantee. The contracts in which those guarantees are contained are in evidence.

Exhibit 84 shows the location of the oil fields in Michigan. There is one little gas field right on the edge, near the Indiana state line; but this map was not intended to do more than show the comparative distances from Chicago to these oil pools as compared with the Texas Panhandle field.

Contrary to the statement just made, gas is being produced and transported from both the Illinois and Michigan fields —not to Chicago, but to other markets. The statement was made that none is being transported from those fields. Gas in appreciable quantities is being transported from the Michigan field and some is being transported from the Illinois field.

(EXHIBIT NO. 84 for identification, offered and received in evidence over the objections of counsel for each of the two commissions, to whom the Examiner granted exceptions.)

I have noted as additional risks or uncertainties the increased capital expenditures and the increased operation or maintenance expenses or costs in the future. Those are more or less related topics, and I think I can cover them together.

I touched briefly yesterday upon the obligation which financial sponsors of such a pipeline as the Natural Gas Pipeline Company underwrite when they make their original expenditure. The original capital expenditure of necessity must take into account certain hazards and risks, some of which are known and some of which are unknown; but once that expenditure has been made, whether gas is able to compete successfully with other fuels or not is perhaps beside the question, because if that pipeline is still to operate and it loses certain markets which it has for some years enjoyed, it may have to spend additional sums of money to seek other markets to avoid the abandonment of its investment before it has been amortized.

Of necessity, even though its operations are successful, it must continue putting in new money each year, and new money in increased quantities each year.

To start with the pipeline does not have a full load. Over a period of years it is successful in developing its markets and does attain the full load. During a certain period of time its drilling operations and expenditures for gathering lines are comparatively low, because of the high open flow and rock pressure in the field, and it takes less wells to meet its requirements; but as the rock pressures decline it
430 is necessary for the pipeline to drill an increasing number of wells each year to supply the required open flow.

Each of those wells must be connected through extensions to the gathering system. Meters, regulators, drips, and facilities of this type are all necessary each time a well is drilled.

In addition to the capital expenditure for providing for the requirements of gas, the pipeline is confronted from time to time with additional capital expenditures to safeguard its earnings and the service it is attempting to render to its customers. Each year this company has found it necessary to lay additional loop lines to strengthen its lines through places which its experience has shown to be unusually dangerous, or to reinforce its river crossings, or to add additional facilities in and around the compressor stations as standby equipment, when experience has shown that the dependability or the amount of equipment available is not consistent with the load it is carrying or is not in proper balance, and these new facilities from time to time, as the conditions develop, call for the expenditure of added sums of money.

I touched briefly yesterday upon our housing program. The amount of money is not perhaps big in terms of millions; but each year this company is finding it necessary to spend sums of money approximating forty to fifty thousand dollars for the providing of housing facilities. That expenditure will not be constant nor will it be continuous every year for the next ten years; but it is an expenditure which has not yet been completed and which must be taken care of. We hope in the next few years we will have completed that program.

I have already said something about field compressor stations. As the pressures decline in the field it will be necessary to install field booster stations to boost this gas to the initial station located at Fritch. The type of station is not important, so far as this discussion is concerned; but it will perhaps be impressive for me to tell you that the program contemplates the installing of a compressor at each and every well in the field before this project is abandoned.

We have made careful engineering studies to try to determine the economics of centrally located field stations, ten, fifteen, or twenty miles apart, as against the installation of automatically remote controlled individual compressors at each well. That is what our program now contemplates, and that program is being started.

Questions by the Examiner.

A part of the research and experimental work which this company has undertaken has been designing those compressors, and one unit is successfully operating on our system in the field today. The pressure of that well is down to just a little over 200 pounds.

Cross-Examination Interposed by Mr. Slaff.

The intake pressure of those field compressors will
431 vary as the pressure goes down. From time to time we will find it necessary to change the cylinders or cylinder sizes or to put in additional capacity.

Direct Examination Resumed by Mr. Morgan.

Answering your question as to what intake pressure those field compressors have been designed for, it will have to fluctuate or change as the field pressures go down.

That, as I says, is not important; but I think it does impressively reflect the extent to which these expenditures are going to have to be made from here on throughout, practically until the day this project is abandoned.

With reference to increased operating expenses and maintenance, when you consider the installation of these field compresor stations, although it is intended that they will be operated by remote control or are virtually automatic, nevertheless there will be maintenance. There will be a certain amount of operation necessary in connection with the units. We will probably provide for a roving field supervisor in certain districts to supervise a certain number of wells and compressors and attend to lubricating, oiling, and the checking of the bearings and water connections, for all those things will require some attendance.

These compressors will be operated on gas fuel, but that will be an added expense to the operation. Those are items which have not yet appeared upon our books. They are items of expense with which this company is denfinitely confronted and definitely committed if it is to go on through to the end of the economic life of the field.

We have other factors involving increased labor and maintenance expense as a result of corrosion and deterioration of the pipeline itself. Inspection of the pipeline

today reveals the pipeline to be in remarkably good condition. There is some pitting, and there is some corrosion. We do not view it with any alarm today, and yet the coating on the pipe, which we think was well applied and there was probably none better obtainable at that time, is nevertheless showing signs of deterioration, and it is our considered judgment that some of those corrosive areas, which are termed by the industry as hot spots, will so affect the strength of the pipe as to make it necessary for the company to operate at materially reduced pressures, and decrease its volume and its revenue from the sale of gas, or to loop those portions of the line or replace the pipe itself.

In the replacement of pipe in a pipeline which is continually operating and serving 210 million cubic feet each day, the line cannot be taken out of service for long intervals to replace joints of corroded pipe, and the program of installing sections of new lines, while that will involve certain interruptions, nevertheless will be the cheapest way of maintaining the line in service in order that it may carry these volumes of gas and maintain potential earnings. This is accomplished by the looping of those portions of the
432 line which become so weakened by corrosion that it is unsafe to carry these prevailing pressures.

The well casings out in the field will become a problem as the wells age, but I think one which, as we view it, will depend more upon the pressures at which the wells are abandoned. Once the casing in a well becomes so badly corroded that top water from the upper formations is leaking in and drowing out the gas, salt formations or salt crystals are formed, and it is a good deal like creeping paralysis. The water is filling these formations and depositing these crystals, and before you are hardly aware of it your well has been destroyed; and while in some instances it is possible to wash the well with fresh water and bring it back and a new casing can be installed, as a usual thing that well whose casing has reached that corroded condition is a well that is ready for abandonment. So that, I would say, becomes more nearly a problem involving the economic abandonment pressure of the field than one of increased maintenance, although there will be cases where recasing the well will be justified.

We will have to have special equipment to provide for blowing the water out of these wells. That will be either a capital expenditure or an increased maintenance item. As these wells develop water, whether it be from the lower

formations or from above, it is the customary practice in the gas fields to install what is termed a liner or tubing. It is a string of pipe of smaller diameter than the casing, which excludes or holds out the formations through which the well has been drilled, and that tubing, being smaller in diameter, offers a means of lightening the column of water so that the reduced gas pressures can lift it and blow it from the well through an unloading device, as they term it. You can lighten the column of water and blow the water from the well with this reduced gas pressure. As the pressure goes down and water intrudes on the formations, there is the probability that not 50% of the wells and not 60% of the wells, but probably 90% of the wells, will have to be either lined or tubed to take care of the water condition.

These are all expenditures. Whether capital or maintenance, they represent an outlay of cash which must come out of the earnings of this pipeline and be recouped, if possible, by the date of its abandonment.

I think I could summarize this item of increased maintenance of the pipeline system best by comparing it with an automobile, a piece of machinery with which we are all familiar. During the early life of an automobile it operates smoothly and needs very little care. The maintenance costs are low; and yet as that automobile is operated over a period of years, just as these engines and compressors are operated, and will be, the wear and tear calls for an increased amount of maintenance, an increased number of repair parts, and an increased number of men to take care of that maintenance. So we are operating this automobile of ours in that stage where it is commencing to take a lot of care to keep it running. Our maintenance costs are going up, but we have not yet by any means reached that point in the life of this project where we are going to suffer the greatest maintenance to keep it operating.

I have caused studies to be prepared, and they will
433 be produced here for the record and for the consideration of the Examiner, of the additional costs in capital investment and maintenance and operating costs which we now feel certain will have to be encountered. These studies have not been completed; but they will be ready, we hope, for presentation at the next session of our hearing, and in that connection I would like to offer this observation: The studies which we are preparing represent studies which are being brought down to date. They represent the best judgment of the engineers, operating men, and executives of this

company, predicated upon our knowledge and experience, not only gained from several years' operation of this project, but experience in the operation of other gas fields and pipelines of shorter length and lower pressures. We have here a different set of conditions to deal with.

These studies, which are being brought down to date, are predicated upon our earlier studies before the Natural Gas Act was passed and before there was any thought that these pipelines would be subject to regulation. We wanted to know ourselves what we were headed for and the amount of money we were going to have to expend, not only upon capital expenditures, but also the extent to which our earnings would of necessity be depleted through increased operation and maintenance. Those studies represent our best judgment and will be in such shape that I hope they will be illuminating upon the points which I have tried to make clear here this morning.

Naturally, we cannot be certain that those figures which will be brought in here cover all the additional expenditures we will make; but we have tried to include those items only which we felt we could safely predict as representing the occurrences which would take place. There are many items which we can visualize may happen, and there is a probability that they may; but if the likelihood is remote we have not included those items. We have tried to include only those which we feel represent a reasonable degree of certainty that they cannot be avoided.

Commenting briefly on the remaining hazards, namely, inflation, taxation, increasing regulatory expense, and the item of pipeline failures, I think I will not take time to more than mention the topic of inflation, since that was covered by Dr. Palyi. The point from a management point of view that disturbs us regarding the possible influence of inflation is the fact that our contracts are based upon fixed sales prices—at least our domestic gas—for long periods of time, and the influence of inflation upon the labor and maintenance items could be so effective as almost to destroy completely our earnings before any relief could be obtained through regulatory proceedings. It is a factor which tends to increase until something disastrous happens, and it seems from history never to decrease. There is a lag prior to the time when a company can show that its earnings are so impaired that it is entitled to relief, and that is a factor which worries the management of this company considerably.

The question of taxation is speculative as to how far increased taxation is going to go and the influence it may have upon the earnings of this company. We only know that since starting the operation of this company we have been confronted with new and increased forms of taxation which have had the effect of increasing the tax pay-
434 ments of all kinds by this company from a sum of $300,000 per year, approximately, in 1932 to a payment of over $1,000,000 a year. The difference, $700,000, may not appear large, but it is an appreciable part of the entire gross earnings of this company.

I would not attempt to go into detail, but I think that we will ask our tax counsel or secretary to furnish details regarding the increase which has taken place in the amount of state income tax, which was non-existent in 1930 and 1929, excess profits tax, capital stock tax, unemployment and old age benefits, sales tax, etc.

There is one very serious tax which looms up every year, and that is the increased production tax in Texas. The present production tax amounts to three per cent of the field value of the gas at the mouth of the well. The total sum of money is not large. I think Texoma's production tax does not at the present time exceed $60,000 a year; but efforts have been made every session, special and regular, of the Texas Legislature to increase that tax from 100% to 1000%, and only by the most vigorous fight has that tax been held down.

In Illinois we have even a worse condition. Since this pipeline entered the State of Illinois it has never been free from attempts, and I say punitive attempts, at taxation. The coal people have sponsored each attempt of the legislature to place destructive legislation on natural gas, and that would affect not only Natural Gas Pipeline Company but the other natural gas companies entering the state.

At the first special session of the 58th General Assembly of 1933, Senator Baker introduced Senate Bill No. 10, proposing a tax of 25 cents per thousand cubic feet on all natural gas sold in Illinois. Our boiler fuel gas sold for industrial purposes grosses this company ten and one-half cents; so obviously it would completely destroy the sale of all gas for boiler fuel. I think I might as well say that that tax would have completely destroyed the sale of every foot of natural gas in the state for industrial use.

Cross-Examination Interposed by Mr. Slaff.

That bill was introduced in 1933, the 58th General Assembly. It was defeated and was not enacted into law. Almost every session of the Illinois legislature has made attempts, and a similar bill did pass the Senate. No law has been enacted; but every legislature has attempted to enact, so the threat is still there. (Motion by Commission Counsel to strike testimony with reference to Bill introduced by Senator Baker denied.)

Direct Examination Resumed by Mr. Morgan.

In the third special session of the same General Assembly, Senate Bill 39 proposed a tax of 15 cents. In the regular session of the 59th General Assembly of 1935, Senate Bill 184 by Baker proposed a tax of 10 cents. Senate Bill 272 by Monroe proposed a tax of five cents per thousand cubic feet. Even the passage of a five cent tax on natural gas, which cuts revenue from boiler fuel virtually in two, would completely destroy that revenue and the sale of gas for that purpose.

435 Senate Bill 272 was proposed in 1935. In that same session House Bill 223, by Koehler and Powell, proposed a tax of 10 cents. House Bill 693, by Stewart, and another, House Bill 740, by Lewis, proposed a tax of five cents each.

In the second special session of the same General Assembly House Bill 60 by Koehler and Powell proposed a tax of 10 cents.

In the regular session of the 60th General Assembly in 1937 Senate Bill 30, by Monroe, and Senate Bill 129, by Tuttle, each proposed a tax of five cents. House Bill 63 by Powell likewise proposed a tax of five cents per thousand. Senate Bill 39, which was introduced in 1933, to which I referred, is the one which I mentioned which passed the Senate and failed to pass the House.

In this session of the legislature two bills have been pending, each of which are five cent gas tax bills. Neither has passed; but the fact that they have not passed does not give us any assurance or confidence that the renewal of these attempts in future sessions, with the influence of the coal miners and coal operators, will not result disastrously upon the revenue derived from the sale of industrial gas.

Cross-Examination Interposed by Mr. Booth.

I cannot state approximately the total amount of taxes which Natural Gas Pipeline Company has paid to the State of Illinois since entering the state. I would not say that it is a very nominal figure. The data can be obtained.

Questions by the Examiner.

Senate Bill 30, by Monroe, in 1937 and Senate Bill 129, by Tuttle, each proposed a tax of five cents. The two bills that were pending in this 1939 session are still resting in the committee, and it is our judgment and our hope that nothing will be done with those. The tax there proposed is five cents.

I would like to observe, however, that the amount of taxes paid by the Natural Gas Pipeline Company to the State of Illinois bears no relation to the loss of earnings which this company would suffer if a punitive charge were imposed upon the sale of natural gas for either industrial or domestic purposes. I say there is no relationship existing between the two.

Cross-Examination Interposed by Mr. Slaff.

I said our taxes increased from approximately $305,000 in 1932 to approximately $1,100,000 in 1938. I haven't the figures before me, but I will accept your word that our
436 gross earnings from operations have increased from $5,857,000 in 1932 to $14,374,000 in 1938. You ask me if it is not correct that, comparing the year 1938 with the year 1937, we had a reduction in our gross earnings from operations of approximately seven to eight per cent, and a reduction in taxes paid of approximately twenty per cent. I would not attempt to say without taking more time. I will say for the purpose of trying to answer your question, without agreeing or disagreeing with your final conclusion, that I will accept that as correct.

Direct Examination Resumed by Mr. Morgan.

The reason taxation has been raised as a topic worthy of consideration in this proceeding is that our taxes are constantly increasing, and there is no indication that the ceiling has been reached. The trend, however, is in the other direction with the pipeline's earnings. The capacity of the

pipeline has been reached. There is every evidence, every indication that the expenses of the company aside from taxes are on the increase. So, if the gross earnings of the company are not subject to material increase, and expenses are on the increase, then obviously such a factor influencing the earnings of the company as taxation, which is continuing to mount, is an item which the management views with concern.

The next item is that of increased regulatory expense. This is an item of expense confronting the company. Hearings of this nature are necessarily items of expense which have not been contemplated, and the frequency with which they may recur in the future is a factor beyond the control of the company, and it is not possible for the management even to estimate the amount of that future expense or the frequency with which they may be called upon to defend rates and earnings.

Under the Natural Gas Act as passed, any consumer, any municipality, large or small, may subject the company to the same expensive type of hearing as the complaint brought by the Illinois Commerce Commission. So it is an item of expense with which the company will in the future be confronted.

There are other types of regulatory expense which we must not overlook but which are difficult to anticipate or estimate. One of them involves the relation of the company with its employees and the relation of the management with the National Labor Relations Board and the Andrews Administration of the Wage and Hour Act. To date we haven't had any difficulty or disturbance with our employees. So far as we know, we hope at least, they are contented and happy. We feel that our salaries are not out of line. We may not be paying the highest, but certainly we are not paying the lowest. But even today labor organizers are attempting to organize the force of the Panhandle Eastern Pipeline and have announced their intention of starting on the employees of Texoma and Natural Gas Pipeline Company as soon as they complete their work with the Panhandle Eastern.

They may or may not succeed; but it is not the intention
of the company to contest their efforts. The employees
437 have the right to speak for themselves. But as to the
outcome, as to increased wages, or what the company may find itself involved in as a result of a decision of the

N. L. R. B. is an item we are not able to anticipate but which must be taken into account.

We have one other item, and this last item to which I refer is a hazard from which we have suffered, and it is one from which we may suffer with increased frequency as the equipment in this line deteriorates through wear and tear or corrosion, and that is the failures of the pipeline and the explosion, burning or loss of compressor stations. We are dealing at high pressure with a highly inflammable and explosive material. On July 4, 1936, as a result of the bursting of a defective joint of pipe in Iowa, which was followed by fire, the company was placed to considerable expense and some loss of revenue in making repairs to the main line.

Again, in February of 1938 the main line failed at approximately 85 miles west of Joliet in Illinois. This failure was due to high water, and caused curtailed deliveries to these interruptible industries for a period of over two weeks before the line was restored to full operation. It resulted in a loss of revenue and expense of making repairs in a total amount of $248,875.

Again, on August 20, 1938, the line failed in central Iowa from causes unknown; but after conferring with the experts of General Electric, Westinghouse, American Telephone, and numerous electrical authorities, it was the cross section of opinion that the explosion might have been caused from lightning. We are not clear on what caused the explosion, but the pipe was not defective. The pipe failed in the steel, but it did not fail in a weld or in a coupling. The grain structure of the metal gave every indication that the steel was in perfect condition, and the conclusion was reached that it probably was lightning.

Mention is made of these failures to show the different types and causes which may result in the company's being placed to extraordinary expense and loss of revenue from reduced sales of gas.

We are confronted with this same serious hazard at each of the 31 rivers which are crossed. They represent potential hazards from which the company will never be free.

Whether the line fails in a flood valley, whether it fails in a river, whether it fails on high, dry ground, there is that possibility that the loss of revenue before service can be resumed may be a very appreciable amount of the company's annual earnings. As to how frequently these breaks

may occur, we only hope that they may never happen; but they will be a potential hazard.

Our compressor stations, operating as they are at high pressures, with a yard full of valves, fittings, welded connections, always offer a potential fire hazard. There seems to be a phenomenon which exists but which has never been fully confirmed, and that is the sudden releasing of nat-
438 ural gas under certain temparture conditions at high pressures results in a flashing or fire following an explosion. It has not been confirmed, but it almost always happens. In fact, I know of no instance where a high pressure gas line has failed without fire following the explosion. Low pressure lines sometimes do.

If on the discharge side of our compressor station, where the highest pressure exists at any point on the line, an explosion should take place as a result of the crystallization of the manifold piping from the vibration that is set up, or as a result of a defective valve or fitting, the tremendous quantity of gas which is being poured into the station would cause a fire which would burn that station down in spite of everything that could possibly be done.

The company has spent considerable money in an attempt to invent or devise automatic main line valves to automatically shut off the main line, instead of the manually controlled valves which take at the best, with the men on the ground, twenty to thirty minutes to shut that gas fully off. Such a device would also reduce the hazards to our employees.

The company has spent a considerable amount of time with Crane, Walworth, and the Merco Valve Company in devising some sort of valve which can be closed instantly by pushing a button, or closed by a sudden drop in pressure, trying to find some way of protecting our stations against the hazard of fire which would probably mean the crippling of the pipeline and its serviee for a period, not of thirty days or sixty days, but at least six months, before we could get the line back in service again.

Our concern over the possibility of fire and explosion at our stations is not a passing fancy. I am sure Mr. Claude Brown, with his experience in natural gas fields and the knowledge of what it means to operate at these pressures, will not minimize what I have said about these hazards.

(Series of photographs entitled "Photographs of Scenes at Pipeline Break Near Sheffield, Illinois, February, 1938", marked Exhibit No. 85 for identification.)

Exhibit 85 consists of a series of photographs, numbered consecutively from 1 to 10, portraying activities and views at the scene of a pipeline break near Sheffield, Illinois, in February, 1938. That is the break which I said put us on partial inability to deliver for a period of about two weeks.

(EXHIBIT NO. 85 for identification, offered and received in evidence without objection.)

Cross-Examination by Mr. Booth.

I do not recall saying anything about a committee representing each of the interested companies working out a contract with Chicago District Pipeline Company. I did not say that the drafting of the agreement was referred to Mr. Gallagher. I said that the price was determined by that set of representatives: Mitchell, Gallagher and Caster. There was no formal committee which worked out the details of this project as well as the contract with the Chicago District. There was a committee, the membership of which varied from time to time, who did sit and con-
439 sider the feasibility of the project and reviewed the comments and recommendations of the engineers as a result of their study and estimates; but that committee was not a committee that functioned without change. At times all of the participants sat with the committee. At other times all members of the committee were not present. It was purely the formation of a body to try to keep the negotiations moving, and the committee drafting the contract involved a group of additional men.

Mr. Mitchell represented the Chicago interest, or the Chicago District. Mr. Rudd was with him at times; but I don't know upon whom he relied as formally representing him. I met with Mr. Mitchell representing the Chicago companies. I did not meet with Mr. Insull. I think Mr. Doherty met with Mr. Insull even before I reached New York in 1929. Mr. Doherty and Mr. Insull were very good friends, and I am not sure but that each time Mr. Doherty came to Chicago he called on Mr. Insull, and each time Mr. Insull came to New York he called on Mr. Doherty. They were both heads of two big utility companies, and as such were very good friends.

Mr. Caster represented the Cities Service, and Mr. Gallagher represented the Standard of New Jersey. There were other men representing the other interested companies, but they varied. For instance, take the Phillips

Petroleum Company. At times Frank Phillips, the president of the company, was there. At other times Mr. Clyde Alexander, vice president in charge of operations, would be there; and at other times W. H. Davis, another vice president; and another time John Kane, executive vice president. It was the same with Skelly Oil Company. Mr. Skelly would be there at times, and at other times he designated the vice president, Mr. Herndon.

I do not recall who the early officers of the company were in addition to myself. There was only one active officer of the company, and by active I mean executive. We had assistant secretries and treasurers and so forth. Mr. H. O. Caster was president of the company; but in that capacity he was not serving as an active officer. I was serving as the active head of the company. Mr. W. A. Jones is president of Natural Gas Pipeline Company today.

Mr. Caster was elected president at the time the company was formed. Subject to confirmation I am willing to try to name the directors at that time from memory. As I recall, they were Caster, Frueauff, representing Cities Service; Christy Payne, Standard of New Jersey; Gallagher may have been or may not but I think he was; Judge Ames of the Texas Company, now deceased, and Judge Caster is also deceased; Reid L. Carr, Columbian Carbon; George Mitchell, Chicago District Pipeline Company; W. G. Rudd, Chicago District. My recollection is that we had eight directors at that time. Jones filled the vacancy created by the death of Caster, and my recollection is that either Colonel Harry T. Klein or Mr. O'Garrio of the Texas Company filled the vacancy caused by the death of Judge Ames.

The board must have approved the entire project and investment which was required for the building of a 440 line, although I don't recall that any formal action was taken. Obviously, six or eight companies would not get together and start without agreeing. I don't recall that there was any formal agreement at that time. They did execute contracts with the Chicago District Pipeline Company. They formed a company in which all of these participating companies had an interest, and when this company was formed through the participation of these various interested companies, officers were elected and contracts were signed, and authority delegated to the active officers to construct and build a pipeline.

Mr. Gallagher was manager of one of the gas properties of the Standard of New Jersey—the East Ohio Gas Com-

pany, in Cleveland. I think he was president of it. He spent some time in working with us and the other members in working out the details of this project; but I would not say he spent any more time than any others in the group.

Cross-Examination by Mr. Slaff.

I testified that in 1926, after making studies at Mr. Doherty's request as to the feasibility of building a pipeline from the Texas Panhandle to Chicago, or to the northeast, with Chicago as a terminus, I arrived at a conclusion and reported that conclusion to Mr. Doherty. I don't believe that report was ever typed. Our conclusion, and by "our" I mean the staff of engineers whose efforts I was directing, left us no doubt, and we were so convinced of our position in the matter that we did not have to go very far to recommend against the project at that time. My recollection is that when we advised Mr. Doherty that we were ready to report our conclusion, my superior, Mr. Straight, general manager of the Empire Gas & Fuel Company, and I were called to New York by Mr. Doherty to discuss the project. Mr. Doherty was and is a very keen engineer, and he wanted to sit down and discuss the engineering principles. He was more concerned with the principles involved than the figures as to what the operations might show.

I couldn't say for sure, but my recollection is that the subject was disposed of orally and not by a written report. During the interim between now and the next hearing I will determine to my satisfaction whether an oral report or a written report was given at that time.

In that connection we made underlying studies to determine whether or not the project seemed feasible. Naturally, we had to analyze the potentialities of the field and try to estimate the cost of pipe, the laying of the line, and so forth. We didn't just carry those figures and conclusions around in our heads; but Mr. Doherty was not interested in those details.

I don't know that those studies of ours leading up to our ultimate conclusion were reduced to writing and in tabular, typewritten form. If they were, I don't know that they are available today. The study had served its purpose when the project was condemned, and we had no further use for those figures. Those figures were obsolete in six

months, so were the figures on the cost of laying the 441 pipe, and also the pipe quotations. In fact, I will say in much less time than that. They were of no value in three months after the study was made. Conditions were changing too rapidly, both as to price of material and conditions in the field. I will be glad to determine between now and the next hearing whether the underlying studies were made and reduced to writing and whether they are available.

At the time it was finally decided in 1930 to go ahead with the project, we made reports, but very few were typed. In our negotiations and our studies to determine the feasibility of the project under a given or assumed set of conditions, I had with me in New York our staff of engineers; but those studies were made from day to day and explained to the interested executives of these companies who later took a participation in the project. Almost as rapidly as one set of figures was reviewed, somebody in the group would suggest compiling figures to see how the results would look under a different set of conditions. In most instances the figures were brought in and explained from penciled work sheets, purely for the purpose of explaining the results to these interested executives who were trying to determine whether they were interested in putting money into this project.

In June, 1930, we transferred our activities from New York to offices which were opened in Kansas City. These were the construction offices of the Continental Construction Corporation, and in these offices we kept our construction files and reports and such preliminary papers as had been retained from the work in New York. When we got ready to leave Kansas City on July 1, 1931, the line was nearing completion, and these studies and files had all served their purpose. When we moved from Kansas City everything except the skeleton records on the construction of the line was disposed of. We even disposed of the pencil figures bearing upon the preliminry studies. They were of no value to us. The decision had been made to build the line, and the pipeline was built, or nearing completion. We did retain specifications, contracts, bills of material, purchase requisitions, vouchers, and those details which would be needed as a permanent record to show the cost of the line and expenditures under classified accounts. We have those records.

I did not say that no formal report was made about

May, 1930, with respect to the feasibility of such a line. One may have been made. If it was, I haven't a copy of it. I will try to determine whether such a report was made. I don't know right now where I would find out. I know I haven't one in my files. I will be glad to ascertain whether such a written report was made. If you know of such a report it would help me in locating one if I knew the date of it. I will also determine whether any of the underlying studies are available.

Redirect Examination by Mr. Morgan.

Without knowing the exact number, but knowing that I am not exaggerating, I would say that there were in excess of one hundred of those preliminary studies made by our engineering corps and given to these executives. Whenever any single study came in before these executives there were at least half a dozen suggestions made as to trying something else, such as let's see how this will look if
442 you are operating at 600 instead of 800; what will the line cost if you use 3/8 instead of 11/32 pipe; how much additional steel will be required, etc. There were some members who thought that we were using too light steel, that we were putting too much stress on the steel with these pressures. We made studies at 300, 400, 450 and up to 800 pounds, and even studies of 1000 pounds pressure. These studies took every possible turn and form before the final recommendation was made.

I doubt if there is a record in anybody's files as to whether it was definitely determined whether this line was going to operate at 500 pounds, 600 pounds, or 700 pounds, but it was designed for a maximum of 800 pounds. That is what we decided it would be. Those studies took every possible turn and form, trying to see what the most economical operation would be.

Cross-Examination by Mr. Booth.

I am not sure that I can state that I testified before any regulatory body regarding this project, except the Railroad Commission of Texas by affidavit. I have mentioned that because of its being initiated by a regulatory body; but it was in court as the result of an order issued by the Texas Railroad Commission.

I did not testify in the Chicago District litigation, either by affidavit or in any other form. I did not testify in the Chicago District Pipeline litigation before the Illinois Commerce Commission or the Federal Court. I did present a statement before the Committee on Interstate and Foreign Commerce in connection with the Natural Gas Act some time ago.

(EXHIBIT NO. 55 for identification, offered and received in evidence without objection, subject to the qualification that counsel, relying upon any part of the exhibit, must refer to that part and explain its pertinency.)

Counsel for defendants, in accordance with the Examiner's qualification relating to Exhibit No. 55, referred to the following portions of said exhibit and called the particular attention of the Examiner thereto.

The first page to which I wish to call attention is the fifth sheet in this report, including the caption page, and over a few pages further there is a page with the following caption at the top: "Coltexo Gasoline Corporation, July, 1932." It is just a few pages past the fifth page.

443 I wish to call particular attention to lines 5 and 6 from the lower horizontal line clear across the page near the top, "Shamrock Oil and Gas Company, Lincoln-Saunders, Well No. 5, potential—" and I am sure the Examiner understands what that means; it is the capacity of the well to produce—"ten; allowable, ten; water, 800." That means 800 barrels of water and 10 barrels of oil; total fluid, 810. Daily gas production, 256,000. Ratio G/F—that means gas-fluid ratio rather than gas-oil ratio; they add the water in with the oil, if I may be permitted to explain.

The next line shows Well No. 3 of the Panhandle Refining Company, with a potential of 40 barrels, an allowable of 40 barrels of oil, 1,000 barrels of water, and a production of gas of 1,755,000 cubic feet.

On the next page I will call attention to the fourth line from the bottom under the classification "One million and above, Gulf Production Company, Saunders No. 1; potential, 1 barrel; allowable, 1 barrel; no water; total fluid, 1 barrel; daily gas production, 1,503,000 cubic feet," and the gas-fluid ratio, the same as the total production.

A few pages over there is another page, "Empire Oil and Refining Company, July, 1932," the second line from the bottom, under the classification 17,500 to 20,000. Magnolia Petroleum Company Well No. 4, potential 93; allow-

able, 93; water, 800; total fluid, 893; total production of gas, 17,606,000 cubic feet, and a gas-fluid ratio of 19,715.

A few pages over, "Forest E. Gilmore Company of Texas, Pampa Plant, July, 1932," fourth line from the bottom, under the classification "One million and above," operators, R. & P. Company, Vaniman Well No. 1; potential, 1 barrel; allowable, 1 barrel; no water; total fluid, 1 barrel; daily gas production, 3,997,000 cubic feet; gas-fluid ratio, the same number.

Nine pages further over, another page captioned, "National Supply Company, Shamrock Plant, July, 1932," under the classification 70,000 to 80,000, Gibson Oil Corporation, Bentley No. 4; potential, one barrel; allowable, one barrel; water, 20 barrels; total fluid, 21 barrels; daily gas production, 1,605,000 cubic feet; gas-fluid ratio, 76,428.

The second page over from that, captioned "Pacific-American Gasoline Corporation," the eighth line from the bottom, under the classification "One million and above," J. M. Huber Petroleum Company, Dumas 1; potential, 1 barrel; oil allowable, 1 barrel; no water; total fluid, 1 barrel; daily gas production, 8,631,000; and the same gas-oil ratio.

Now, it must be twelve pages over there is another caption, "Skelly Oil Company, Panhandle Plant," and in parentheses, "4", July, 1932. I read from the line immediately above the second horizontal line from the bottom, under the classification, "One million and above," Empire Oil and Refining, Weatherly No. 6; potential, one-half barrel; allowable, one-half barrel; water, one barrel; total fluid, one and a half; daily gas production, 1,528,000; gas-fluid ratio, 1,018,666.

It must be twenty-one pages over, I call attention to another page, "Standish Oil Company, July, 1932." It is
444 a group of figures beginning three lines from the bottom and continuing through that block of figures, under the caption, "One million and above," Gulf Production, Johnson No. 14; potential, 1 barrel; allowable, 1 barrel; no water; total fluid, 1 barrel; daily gas production, 5,381,000; and the same gas fluid ratio, which, of course, means gas-oil ratio in this case.

Phillips Petroleum Company, B. Daves No. 1; potential, one barrel; allowable, one barrel; no water; fluid, total, one barrel; gas production, 3,885,000, and the same gas-fluid ratio.

Phillips Petroleum Company B. Daves No. 2; potential,

one barrel; allowable, one barrel; total fluid, one barrel; daily gas production, 1,337,000, and the same gas-fluid ratio.

Phillips-Prairie, Johnson "A" No. 69; potential, one barrel; allowable, one barrel; no water; total fluid, one barrel; daily gas production, 5,015,000 cubic feet, and the same gas-fluid ratio.

I think there is one other, over some ten pages further on, under the caption, "Standish Oil Company, Rock Creek, 1932, page 3." It is the group of figures above the lowest horizontal line, under the caption, "One million and above;" Derby Oil Company, Keaton No. 2; potential, 2 barrels; allowable, 2 barrels; no water; daily gas production, 6,437,000 cubic feet; gas-fluid ratio, 3,218,500 cubic feet.

Derby Oil, Keaton No. 4; potential, 2 barrels; allowable, 2 barrels; total fluid, 2 barrels; daily gas production, 3,309,000; gas-fluid ratio, 1,654,500.

Hudson Drilling Company, Johnson No. 1; potential, one barrel; allowable, one barrel; no water; total fluid, one barrel; daily gas production, 4,489,000; gas-fluid ratio, the same.

Mark Fenston, Peterson No. 1; potential, one barrel; allowable, one; water, one; total fluid, two; daily gas production, 4,252,000; gas-fluid ratio, 2,126,000.

Phillips Petroleum Company, Gowland No. 1; potential, two barrels; allowable, two barrels; no water; total fluid, two; daily gas production, 4,516,000; gas-fluid ratio, 2,258,000.)

445 J. G. DICKINSON, a witness for defendants, testified as follows:

Direct Examination by Mr. Morgan.

(June 30, 1939.)

My name is J. G. Dickinson. I live in Amarillo, Texas. I have lived there since 1931, and I also lived there one year in 1926. Since August, 1930, I have been general superintendent of gas production of Texoma Natural Gas Company.

I received a degree of Bachelor of Science in electrical engineering at the University of Alabama in 1917, and immediately after leaving the university I was employed

by the Toledo Railway & Light Company on constructive work, and in the latter part of 1917 I enlisted in the army during the war. While in the army I received technical training at the Massachusetts Institute of Technology, in aviation work. After the training I was transferred to Carruthers Field in Fort Worth, Texas, where I had charge of the maintenance and repair of approximately 75 planes. I stayed in the army until the early part of 1919, when I was employed by the Empire Gas & Fuel Company, at Bartlesville, Oklahoma, and remained in the service of that company until August, 1930, when I went to the Continental Construction Corporation and later to Texoma.

In 1919 I first went to work for Empire Gas & Fuel Company in their central office, and later was transferred to Eldorado, Kansas, where I worked on the first large scale adaptation of electricity to oil field operations, and during that period I supervised the drilling of the first oil well in the midcontinent field to be drilled by electricity.

I remained in the Kansas field until 1923, when I was transferred to the central office in Bartlesville, where I did engineering work for the manager of oil production, and during the same year was made division superintendent of oil production for northern Oklahoma. In 1924 I was made superintendent of oil production for eastern Kansas. In 1925 I became superintendent of oil production for north Texas.

In 1926 I was made superintendent of oil production for the Texas Panhandle, and I opened a division office for Empire Gas & Fuel Company in Amarillo, Texas, in 1926, in which office we had geological, land, lease and production activities. At that time I remained in Amarillo one year.

I then went to Eldorado, Kansas, where I became superintendent of production for the State of Kansas. During this assignment we had the operation and maintenance of approximately 60 gas wells in addition to oil field operations.

446 During the interval between 1926 and 1930 I followed the development in the Texas Panhandle very closely. The Panhandle field was quite active in its development and I followed the history of that development very closely.

When I first went with the Continental Construction

Corporation in July, 1930, I lived in Kansas City, Missouri. I remained there until August, 1931, when I went to Amarillo and opened an office for Texoma. We established production, geological, land and lease activities to be administered from Amarillo. I have been in charge of that office for Texoma and have administered the duties of those departments since I went there in 1931.

When I first went with Continental Construction Corporation, predecessor of Texoma, I organized the land and lease, geological and production departments, and with Mr. Peterson made a study of the gas reserves in the Texas Panhandle field. At that time I informed myself concerning the situation in that field as to whether or not the lands were under oil and gas leases. Practically all the field was leased up when I went to Amarillo.

I am acquainted with Exhibit 80. That exhibit shows in red the lands that were covered by oil and gas leases as of August, 1930. The heavy black line represents the Texas Railroad Commission's boundary as of 1937. Some of those leases were taken as early as 1919 or 1920; but the principal amount of leasing took place in 1926, or about the time active oil development started.

I am familiar with oil and gas leases and how they are kept alive. An ordinary oil and gas lease conveys title to the oil and gas in the land described in the lease usually for five or ten years. Those leases provide that they shall continue in full force and effect for a period of five years, ten years, or some term of years, and as long thereafter as oil or gas is produced in paying quantities, or in some instances as long as oil or gas is produced. They also contain a provision that they will terminate at the end of a given period, usually one year, sometimes six months, unless a well be commenced in the meantime or a rental of a certain amount be paid on or before the expiration of that period.

Most of the leases outside of the oil fields and outside of a few localities where gas wells had been drilled were kept alive between the period when they were executed and August, 1930, by the payment of rentals. The usual rental payments are $1.00 per acre per year. Probably 90% of the leases in the field carry that provision.

The number of leases, some of which were entirely outside the field, which were being carried on a rental basis as late as August 1, 1930, is accounted for to some

extent by the fact that the boundary of the field was not definitely known at that time. There was considerable lack of information as to the extent of the field then.

It is the usual practice of oil and gas companies and others who are in the oil and gas business, when a discovery of oil in large quantities is made, such as was developed in the Panhandle in 1926, to try to buy some acreage close to the well, for which they usually had to pay a high price, and in addition they usually bought spreads of acreage. By spreads of acreage I mean acreage located in different tracts, separated from the well by as much as four to six miles. The reason for this is that definite information concerning the extent of the discovery is not available to the operators, and the operators like to protect themselves with acreage in the vicinity.

As late as 1930 there was so much uncertainty about the field that those who had oil and gas leases, or were dealing in oil and gas leases, did not know every time when they were in the field. There was considerable uncertainty as to the potentialities of certain areas in the field. We had cases where large wells were close to small wells; and very little drilling had been done in Moore County at that time.

It was known in 1930 that there was sour gas and also sour oil in that field. It was generally known that sour gas prevailed in southern Hutchinson County and northeastern Carson County, and that part of Gray County west of Pampa, close to the north line of the field; but it was not known how far down in Carson, Gray and Hutchinson Counties that sour gas extended. The sour gas was known to be in the oil field area, and that is about as much as we knew at that time. There is no visible barrier on the top of the ground which separates the sour gas from the sweet gas areas in that field, nor is there any barrier below the ground which separates them. As a matter of fact, the formations that produce sour gas in parts of the field produce sweet gas in other parts. In other words, the same formation, beginning on the lower or northeast flank of the field and extending up structure toward the granite ridge which we have heard mentioned in this hearing, will bear sour gas to a certain point, and then the gas will become sweet in that same formation.

In 1930 we did not know where that line which divided sour and sweet gas was located. We did know that wells to the north produced sour gas and that wells toward the south end of the field produced sweet gas. In some cases we had sulphur tests of the wells that produced sour gas, and we did have some idea from that as to where the dividing line was. We had to interpolate between wells. In some cases it would be eight to ten miles between them; but with the aid of the sulphur tests and the knowledge that some gas was sweet, we did make an effort to locate that sour gas line.

That rather tentative location of that line did not apply to the full length of the field. At that time no sour gas was reported in Moore County. One or two wells had been drilled, but they had been reported as sweet gas wells. As far as we knew, the whole of Moore County was in the sweet gas area.

I had something to do with the assembling of blocks of acreage which were afterwards acquired by Texoma, and with appraising them, not in terms of dollars but for prospective production. We made a study of the acreage situation, and we received from various acreage holders their statements of their oil and gas leases, and we made a study of the acreage held in the field by all the owners in the field.

448 There was practically no acreage at that time which was not under lease. The owners of the oil and gas rights at that time were principally the oil companies operating in the field. Some of the oil companies operating in the field and which had large blocks of acreage productive of gas were the Humble Oil & Refining Company, Gulf Production Company, Texas Company, Phillips Petroleum Company, Skelly Oil Company, Shamrock Oil & Gas Company, Canadian River Gas Company, Red River Gas Company, Empire Gas & Fuel Company, Columbian Carbon Company, Magnolia Petroleum Company, Piney Oil & Gas Company. There was also a large number of independent operators, such as Cree & Hoover and Wilcox Oil & Gas Company. I don't recall the others at this time.

I referred to the Gulf Production Company acreage. It did not own that acreage in 1930. It had been purchased at that time by the Chicago utilities. As to the acreage owned by Canadian River and Red River Gas

Companies and the Cities Service Company, the gas rights had been acquired by those companies and the acreage had been dedicated for gas pipeline use. They were not for sale to another pipeline. The blocks of acreage which were available for purchase to put behind this project were principally those held by the oil companies.

We considered all the larger blocks of acreage in connection with this project. We paid particular attention to the large blocks of acreage because we felt it necessary to provide the pipeline with adequate reserves. We also felt, after making a study of the situation, that it was going to be necessary to acquire practically all the large blocks that were available, and some of the other acreage in addition. We thought that was necessary because, after making a study of the field, we felt we should acquire reserves, and we were conscious that the oil operations were going to bring about an enormous production of gas in particular parts of the field, and we not only felt that we needed large amounts of acreage, but we felt that we needed to have it distributed rather widely over the field.

We needed to have it scattered over the field because we had seen that several areas in the field after the development of oil were producing enormous quantities of gas, and a great deal of it would be wasted to the air. Since oil could be produced on a flank of the structure, we felt that other oil areas would be opened up in the field, and we did not know to what extent gas withdrawals would be concentrated in this particular area.

There had already been substantial oil production in the Borger area. There had also been a few wells drilled in northeastern Carson County. There was an area south of Pampa in Gray County which had developed oil. One oil well had been drilled in central Gray County near the north line. One or two oil wells had been drilled in the northwestern parts of Wheeler County. One well had been drilled across the river in Hutchinson County; and a small area had been developed on the Burnett estate in Carson County. There was then a continuing exploration by the drilling of wells, and we expected that this exploration would probably develop other similar situations.

449 The thing which caused us to think about the oil fields in connection with acquiring reserves was that

in the early days it was the custom of the operators to let those wells blow, if they produced gas, for days and days, in the hope that they would blow into oil wells. There were some wells drilled near the oil-gas contact line which, after blowing for some period, started to produce oil. In general, there was an utter disregard for the value of the gas on the part of the oil operators. This practice had resulted in the development of low pressure areas in the oil area, and it was obvious that the waste of gas was going to cause drainage into the oil field areas from the gas areas. I am familiar with the subsequent history of that field, and our fears a[illegible]ng that line were well founded.

There are now forty oil pools in the field, and those oil pools have uniformly resulted in the formation of low pressure areas, with the exception of the dolomite area, which is outside of the gas area. Those developments have caused waste of gas, with the exception of the dolomite wells. The dolomite area is along the northeast flank of the field and is outside of the area that produces gas.

Texoma acquired acreage from the Magnolia Petroleum Company on April 12, 1930. It also acquired acreage from the Texas Company, the Phillips Petroleum Company, Skelly Oil Company and Piney Oil & Gas Company. We acquired the Gulf Production acreage from the Chicago utilities, and acreage from the Cities Service Company.

The Piney Oil & Gas Company was a subsidiary of the Columbian Carbon Company. The Delmar Oil Company is a subsidiary of the Indian Territory Illuminating Oil Company, which is a subsidiary of Cities Service.

Texoma acquired approximately 316,000 acres. The effective date of the transfer of this acreage to Texoma was August 1, 1931, but the settlement for the leases was made as soon thereafter as it was practical, and by August 21, 1931.

Exhibit 81, styled "Leases Owned by Texoma Natural Gas Company in Texas Panhandle Gas Field, August 1, 1931," was prepared in our office at Amarillo. The date August 1 was used instead of August 21 because the effective date of the transfer was August 1, 1931. The assignments bore that date. After that there was the question of the delivery of the assignments and the pay-

ment of the moneys, but the leases were ours from August 1, 1931.

Title was taken August 1, and settlement and the exchange of necessary papers was made subsequent to that, as of August 21, but the title relates back to August 1, 1931.

(EXHIBIT 81 for identification, offered and received in evidence without objection.)

In these transfers in August, 1931, Texoma acquired 1,009 leases. Under the terms of those leases 1,009 wells, including those already drilled, would have been required to keep those leases in force. It was not my thought, as general superintendent of production in charge of Texoma's acreage down there, that all of those 1,009 wells 450 would be drilled and developed to produce natural gas. We were certain at the time the leases were acquired that we would not drill them all; but it was necessary to acquire a great deal of acreage that we knew we would not keep in order to get the acreage that we wanted to keep. We did not know at that time what we wanted to keep and what we did not want to keep. In the first place, we did not know the extent of the field. We did not know very much about what areas would be most productive of gas. We did not know the extent of the oil field operations with its continuing waste of gas, and we did not know definitely the location of the sour gas line.

That is not an unusual difficulty confronting a pipeline company or an oil company in acquiring acreage in a developing field. It is a usual difficulty. When an oil company goes out to drill prospective locations, it is customary for them to take a spread of acreage, or a heavy block of acreage covering more than they know or have any idea will definitely be productive.

I will illustrate that this way: although they may have geological information concerning the value of a particular area, when they get down 2500 or 3000 feet in the ground the same conditions may not prevail there as prevail on the surface, and it is customary to take acreage in spreads with the idea that they will only eventually keep the good part of it.

It would not have been possible at the time I went to Amarillo, or at the time I became superintendent of production, to have gone through the Panhandle field and picked out 150,000 acres of land that could be bought

and which we were certain would be productive of gas. We could not have bought 150,000 acres and picked it out that would have been as productive of sweet gas as the acreage Texoma has now, because we did not know enough about it. You couldn't have bought it in that manner anyway. We bought all we could, and then we, with selectivity, kept the best part of it, and we now have the 150,000 acres, so it is obvious that we couldn't have done it with less acreage than we started out with.

What we were interested in was acquiring a gas reserve, and we were conscious at the time we went into the field that it was going to be necessary to select out of the acreage that we did acquire that part of it which would be suitable for supplying the needs of the pipeline. In different portions of the field some wells had been completed with initial open flows of as much as 100,000,000 cubic feet per day. There had been a number of dry holes drilled in the field, and quite a few wells with two or three million cubic foot capacity.

We would have liked to pick out the acreage close to the 100,000,000 cubic foot wells and to have kept as far away from the two and three million cubic foot wells as we could in buying the 150,000 acres. As a matter of fact, we did try to select acreage that we wanted, but we found that we were not able to buy the best part of the acreage because the companies would not sell it that way.

Another thing is that those leases in the better areas might be held by quite a number of companies; but
451 probably the principal reason was that we didn't know where those areas were at that time. Some of the acreage we thought at that time was going to be among the best has turned out to be not so good, and several areas that we did not think much of have turned out to be very prolific.

We could not have traded with the Magnolia, for instance, on the basis of picking out what we thought was the best acreage they had and buying it for $50.00 or $40.00 an acre. They demanded $2,000,000 for their acreage. They were willing for us to take what we wanted of it, but that is what it would cost. We would have all of it for that or just a part of it for that.

That was not an unusual situation to find in the field at that time among those who had large blocks of acreage to sell. The oil companies were not willing to sell their

choice acreage and have left on their hands the other part. When they sold gas acreage in the field, they sold all of it.

As to how we intended to handle the 1,009 tracts of land which were embraced within the 1,009 leases we first acquired to determine which we would keep and which we would surrender, we drilled wells on some of it ourselves. There were already 69 wells on this acreage, and we purchased them when we bought the acreage. We drilled some wells ourselves. Subsequent drilling by others has also given us information on which we base our acreage policy.

We started out to improve the situation so far as drilling obligations were concerned by trading or consolidating our acreage into desirable blocks. We knew in the beginning that we were not going to drill all of the 1,009 leases; but since most of the leases which we acquired were term leases, that is, they would expire in periods of from one to ten years, we knew that unless we made some consolidations of leases we would be confronted with an excessive drilling program early in the life of the project when those wells would not be needed.

So we made efforts to combine the leases which we acquired from various oil companies into large units, which we termed consolidations. Those consolidated agreements provided that one well would be adequate development for a large tract of land and that offsetting wells would not be required. We were able to make agreements of this kind because we prorated our gas production on the basis of the open flow of the wells and the acreage upon which the wells were located. By making consolidation agreements of this character, we were able to defer a considerable amount of drilling until the wells were required for the pipeline to supply its daily needs.

In making these consolidation agreements we acquired new acreage by purchase or by the drilling of wells, and we traded acreage in the sour gas area for acreage in the sweet gas area. We not only made consolidation agreements on the land of a single land owner, but we made agreements covering the lands of several land owners, apportioning the royalty in proportion to the land which they held and the open flow of the wells which might be drilled on the unit.

452 Instead of having to drill a minimum of a thousand wells, we now have 163 wells. We don't know how many wells we are going to have to drill; but I am sure it will not be half as many as the 1,009 we would have been required to drill.

On Exhibit 81 the tracts colored in pink or red represent the leases in the Panhandle field acquired by Texoma as of August 1, 1931. Other leases had been discarded by Texoma after the commitments were made and before title passed. After the commitments were made some developments indicated that some of the acreage might be outside the proven area or in the sour gas area, and prior to our actually taking title we recommended the surrender of some acreage to keep from paying rental and to keep from having the expense of putting it on our books and then having to let it go.

Several reasons entered into the surrender of acreage from time to time. Some of it was in an area which was non-productive. Some was located in an area of low rock pressure. Some acreage was too far from the pipeline, consideration being given to the potentialities of the area which was deemed to be too far away to be practical to connect to the line. Some of it was released on account of lease expirations. Some was released to avoid offsetting drilling requirements. Some was released because the acreage was in small tracts which we did not consider economical for drilling units.

In cases where we could, we consolidated those small tracts and made large ones out of them. In a good many instances we were not able to consolidate them.

Taking into account all of the acreage which we released, that which we received in exchange and that which we conveyed away in exchange, and the new purchases from time to time, Texoma owned and retained as of January 1, 1939, approximately 154,000 acres. That acreage is located along Texoma's gathering system and generally in what we consider the best part of the field, consideration being given to open flow and rock pressure. Approximately 316,000 acres are portrayed on Exhibit 81. In other words, we retained approximately half of the acreage which we acquired.

Exhibit 68 is a map of the Texas Panhandle field on which has been colored in red the acreage owned by Texoma as of January 1, 1939. This map was prepared in our Amarillo office under my direction, and correctly represents as to its location the acreage Texoma owned as of that

date. All of that acreage is under lease to Texoma and Natural Gas Pipeline Company, and out of that 154,000 acres approximately 100,000 acres is covered by consolidation agreements.

There are 360 acres colored on that map on which Texoma does not own the gas rights but owns only the oil rights. This is because of two oil and gas leases which we acquired in trades or purchase and on which we traded the gas rights for other gas rights better located with respect to our 453 other acreage, and retained the oil rights. One of those tracts is located in southeastern Moore County, being the southeast 1/4 of Section 34, Block 6-T, containing 160 acres. The other 200 acres is located in Section 145, Block B-2, H. & G. N. Survey, in Gray County. Texoma now owns the gas rights on 154,155 acres, less 360 acres.

The responsibility of culling over and ferreting out those tracts of land which are less desirable for the uses of the pipeline, and recommending the surrender of those tracts, has been mine. I have followed the details of that work of selecting and rejecting acreage from that originally acquired throughout the history of this company.

If we had retained all of the 1009 leases which we originally acquired, and drilled wells on each of them, we would not have been able to produce any more gas from the Panhandle field down to date than we have produced and carried away to market through our pipeline. If we had wells on all of those leases now, we would not be able to produce and market over the future life of the field any more gas than we will be able to market from the wells which we propose to drill on the acreage which we have retained.

My statement that we can produce and market as much gas from the 154,000 acres as we could have from twice that number of acres is based on the fact that the amount of gas which Texoma will market is going to be determined by the life of the Panhandle field as a whole. By that I mean that Texoma will reach the same point, where it becomes economically necessary for it to abandon its operations and leave the field, by taking its gas from its retained acreage as from taking it over the acreage which it first acquired, and it will do that at a great deal less expense.

By reducing the number of acres retained we have eliminated the payment of rentals, taxes, expense of drilling a large number of unnecessary wells, and the expense of gathering lines, meters and compressor stations. The drilling

of unnecessary wells would involve the laying of unnecessary gathering lines and installing unnecessary meters.

In the early days we had a geological estimate that the average production of gas per acre would be approximately 8,000,000 cubic feet. Mr. Peterson's current estimates approximate 17,000,000 as the original reserve on the present acreage, so that we have about as much gas now as we thought we had when we bought all this acreage.

The Cities Service Gas Company owns approximately 103,900 acres in the Texas Panhandle.

(EXHIBIT 68 for identification, offered and received in evidence without objection.)

Cross-Examination by Mr. Booth.

Before we took title on August 1, 1931, to the acreage in Moore County which had been taken over by the Chicago interests, there had been some indication of sour gas in Moore County. That information was indefinite, but we did know there was some sour gas in Moore County at that time.

454 In the preparation of reports or negotiations leading up to the acquisition of this acreage in the Panhandle by Natural Gas Pipeline Company or Texoma, my part was to advise Mr. Brown concerning our thoughts with reference to the field. I took no other part in the negotiations. I worked for Mr. Brown from August, 1930. At that time the acreage was not primarily of a sour gas character. It is true that some of the acreage acquired from the Chicago interests or the Insull company turned out to be sour; but at the time I was consulting with Mr. Brown about that it appeared that a comparatively small part of it would be sour. My studies in 1930 did not disclose that 50% of it was of a sour gas character. In 1930 we thought about 20% was sour. I don't think more than 35% of it was ever found to be sour.

I don't have the figures in my mind as to how much of that acreage we relinquished. I don't know what Mr. Brown thought in 1930. I think it was my thought at the time that this Gulf acreage that we acquired through the Insull interests was partly sour. The information we had at that time was not definite, however. By the latter part of 1930 we knew that some acreage was outside of the productive area and we knew that some was sour. In considering the purchase of the acreage we were guided principally by the

fact that they had a considerable amount of sweet gas acreage. As far as we knew in 1930, before the acreage was turned over, we considered about 20% of it sour at that time.

Redirect Examination by Mr. Morgan.

Sour gas is not outside the range of use by pipelines. It can be treated, and during the early considerations having to do with acreage reserves, we derived some satisfaction out of the thought that if it was necessary we could treat this sour gas and use it. We did not turn it loose until we knew definitely what character of sweet gas land we had. That was done only after we found we had an adequate reserve of sweet gas.

The treatment of sour gas to make it useful for pipeline purposes is chiefly absorbing the hydrogen sulphide elements in an absorbing medium, and the generation of that medium, and using it over and over again. The cost in a central treating plant would be about half a cent a thousand. I know of instances where sour gas is being thus treated and used for ordinary pipeline purposes, where they have no sweet gas available. One instance of that is the gas that goes into El Paso, which is treated in southeastern New Mexico. There are several sulphur treating plants, one operated by the Northern Natural Gas Company in the Otis field, and one by the Cities Service Company near Wichita. In fact, they are rather numerous throughout the country. If the acreage owned by Texoma which turned out to be sweet gas areas had turned out not to have been an adequate reserve of gas, we would undoubtedly have treated the sour gas and used it.

So that the record will show the total quantity of 455 acreage acquired from each of the companies from which Texoma bought its original block, totalling 316,104.79 acres, I will read the following names of companies and the acreage acquired from each:

Cities Service Company,	59,388.87	acres
Columbian Carbon Company,	10,687	"
Delmar Oil Company	2,877.90	"
Chicago utilities	82,441.02	"
Magnolia Petroleum Company	50,069.70	"
Phillips Petroleum Company	34,621.34	"
Skelly Oil Company	26,956.50	"
Texas Company	49,062.46	"

Questions by the Examiner.

I do not have with me a tabulation of those eight sources of acreage showing the amount of acreage remaining today from each source. I might say that from the begininng we have handled this acreage proposition as a whole, without consideration as to where it came from, and I do not have in mind what that situation would be.

Redirect Examination by Mr. Morgan Resumed.

We think in terms of our whole holdings, rather than from whom we bought it.

I keep up with the operating problems in connection with the production of gas from Texoma's wells. We have operating complications and troubles in connection with the production from gas wells such as occur in the case of oil wells. We have a similar condition. Shale caving occurs in both oil and gas wells. By that I mean that in drilling the producing formations it is the usual case that shale lenses and shale layers occur between the producing formations. This occurs in the open hole down below the seat of the casing.

The kind of problem that creates is that usually in the operation of a well there is some moisture from the very beginning which is saturated in the gas that drops out immediately upon the release of the pressure. This moisture gets on the sides of the walls of the hole and causes the shale particularly to slough off and drop down into the hole. It has some influence also on the lime in making it drop off. Sometimes these cavings form in a bridge and completely stop the flow of gas. On these occasions it is necessary to move in tools and drill this bridge out. If a bridge does not form and the shale caves and falls in small particles to the bottom of the well, and a considerable portion of your production comes from the bottom of the hole, it will shut that part of the production off, and then we have to clean it out. That requires a drilling machine, or what we call a cleanout machine, which consists of a portable mast and machinery to spool wire lines on, and it requires the services of a man versed in the handling of cleanout jobs, as well as the crew that works on the well.

We have also encountered other operating problems
456 besides these cleaning difficulties. In wells that produce any appreciable amount of salt water, it is neces-

sary to install tubing in order to get this water off of the producing horizon satisfactorily. This tubing restricts the area of flow. The tubing which we use in gas field operations is usually two inch pipe, whereas the diameter of the hole is approximately 8¼ inches. This tubing is run to the bottom of the hole or to the gas pay horizon, and when the well is blown it is blown through the tubing, so that the area of flow is restricted and the bubbles of gas reduce the weight of a column of water to such an extent that it can be blown out with a smaller amount of gas and a smaller pressure than if you were blowing out the water in the big hole. That is a practical and generally used device for the purpose of assisting in the removal of water.

We have, I believe, 26 wells now making water. Not all of those are still on production. We have abandoned eight of them, leaving 18 wells still on production and making water. It is becoming more apparent that water is going to affect the production of gas wells in the future, and that will require increased use of these provisions for removing water as time goes on.

Cross-Examination by Mr. Slaff.

The acreage in central Moore County was acquired from a number of sources: Phillips Petroleum Company, Magnolia, Cities Service and Chicago utilities. Mr. Brown said there were 30,000 acres acquired from Magnolia in that area in Moore County, southeast of Dumas. In addition to the block of 30,000 acres in there, we also acquired considerable acreage from other companies that fitted in around this other block. There is a good deal more than 30,000 acres represented by this central block of acreage.

The solid block of acreage represented on Exhibit 81 in the southeasterly portion of Moore County came principally from Phillips Petroleum Company. Another comparatively solid block of acreage is shown in the northeasterly portion of Carson County. Some of that came from the Chicago utilities, some from Magnolia, some from Skelly, and some from Cities Service Company. I do not know approximately how much came from each.

United Gas Pipeline Company has some acreage in the Texas Panhandle field. I do not know how much, but I think it is a comparatively small amount.

(July 24, 1939)

(Document entitled "Statement of Open Flows and Rock Pressures on Date Wells Were Abandoned, Eldorado and August Fields, Butler County, Kansas. Charles I. Galloup, Witness.", marked Exhibit 86 for identification.

EXHIBIT 86 for identification, offered and received in evidence over the objection of counsel for complainant as being hearsay to whom the Examiner granted an exception. The exhibit was not offered as proof of anything but as in compliance with the request made by counsel for the two commissions to produce the report. Company counsel did not represent its truthfulness.)

457 J. G. DICKINSON, a witness for defendant, recalled, testified as follows:

Direct Examination by Mr. Morgan.

(July 24, 1939.)

In meeting the duties and responsibilities of my position as general superintendent of production for Texoma Natural Gas Company, I have made it my business to keep informed as to the quantity of gas withdrawn from that field and the uses to which that gas is put. I have done this for several reasons. One is that the withdrawals of gas from the entire field affect the life of the field and this information is vital to Texoma. Another reason is that we have had considerable litigation with the Railroad Commission of Texas which made it necessary for me to keep up with the entire history of the field. A third reason is that information as to withdrawals of gas in the field is necessary in the handling of Texoma's acreage.

The withdrawals of gas at different points in the field affect the pressures in the field, and information as to the pressures is important in consideration of Texoma's development program, and we give considerable importance to our knowledge of withdrawals in determining what leases of Texoma's will be retained and what leases will be surrendered.

I have informed myself concerning the different groups which are withdrawing gas from that field and the requirements of those groups at the present and in prospect. There are nine pipelines with lines 14 inches in diameter

or larger which take gas from the Panhandle field. In addition to those nine, there are a number of lines serving local areas in the field.

Others than pipelines are taking gas from the field. Gas is withdrawn from the field for processing in casinghead gasoline plants, some of the residue of which goes to the manufacture of carbon black. Gas is utilized in the drilling of wells for fuel and is blown to the air and wasted in the process of drilling wells.

I have used the expression "casinghead gasoline plants." That is a popular designation in Texas which I think is a misnomer, because those plants process not only casinghead gas but a majority of dry gas. All of the sour gas produced there goes to these plants.

One other sort of gas withdrawal which I have not covered is gas produced from oil wells which are not connected to casinghead gasoline plants. That gas is blown to the air and wasted.

I will name the nine larger pipelines which I mentioned a moment ago.

Texonia Natural Gas Company serves principally the Chicago area and its vicinity.

458 Canadian River Gas Company supplies cities and towns in New Mexico and Colorado. Its principal outlets are Denver, Colorado Springs and Pueblo. When I mention the Canadian River as having those outlets, I mean the system to which it belongs. It delivers gas to Colorado Interstate Pipeline Company, which in turn serves the area I mentioned. Canadian River Gas Company also has a local line which serves the city of Amarillo.

Panhandle Eastern Pipeline Company serves towns and cities in Missouri, Illinois, Indiana, Ohio and Michigan. Its principal outlet is Detroit and vicinity.

Northern Natural Gas Company supplies markets in Nebraska, South Dakota, Iowa and Minnesota. Its principal outlets are Des Moines, St. Paul and Minneapolis and vicinity.

Cities Service Gas Company supplies towns and cities in Oklahoma, Kansas and Missouri. The principal outlets are Wichita, Kansas, and the Kansas City, Missouri, area.

Lone Star Gas Company supplies numerous towns and cities in northern Texas. Its principal outlets are Fort Worth and Dallas.

North Texas Utilities Company supplies an area in north Texas, the principal outlet being Wichita Falls and vicinity.

Consolidated Gas Utilities Corporation, heretofore known as Texas Panhandle Gas Company, supplies towns and cities in Oklahoma and Kansas, the terminus of the line being near Wichita, Kansas.

The South Plains Pipeline Company, sometimes designated as the West Texas Gas Company, supplies a large area in West Texas. The principal towns served are Plainview, Lubbock, Big Springs, San Angelo, and others.

In addition to these nine pipelines, I will enumerate the principal smaller lines I mentioned a while ago. I have already mentioned a local line serving the city of Amarillo. There is a line serving Pampa, Texas; Panhandle, Texas; Borger, and a group of towns in Wheeler County, the principal one being Shamrock, Texas. There is a local line that runs to Stinnett and Spearman, Texas.

Most of these pipelines produce a large proportion of their withdrawals from their own reserves. Some of them purchase some gas. The companies which purchase substantial quantities of gas in that field are the Lone Star Gas Company, North Texas Utilities Company, Panhandle Eastern Pipeline Company, and Northern Natural Gas Company.

The average price at which those pipelines purchase their gas and pay for it at the well or in the field is a little over four cents per thousand cubic feet. Settlement of Texoma's royalty payments is now being made on the basis of four cents per thousand cubic feet, and that basis of payment continues until December 31, 1939, when the price becomes four and one-half cents per thousand cubic feet.

459 The price at which we settle with our royalty owners has not always been four cents down to and including the present year. In the beginning, when Texoma first started operations in the Panhandle field, the field price paid by a number of companies was two cents per thousand cubic feet, and that was the basis of the first royalty settlements of Texoma. This was later changed to three and a half cents. The three and a half cent period covered three years, when the price of four cents was adopted. This rate continued for five years, which ends December 31 of this year. The four and a half cent price which will prevail after December 31, 1939, will continue for a five year period, and this price is recited in Texoma's division orders which it executes with the royalty owners. This is a contractual price fixed between Texoma and its various roy-

alty owners. I don't remember the exact number, but we have several hundred royalty owners down there. At the expiration of five years from January 1, 1940, the price becomes 5¢ per thousand cubic feet, and continues at that price for the remainder of the life of the field.

The reason for stepping up the price from two cents in the beginning, next to three and a half cents, then to four, next to four and a half, and finally to five cents, is because it is generally recognized that as pressures decline in a gas field the cost of producing gas increases. This is due to the necessity of drilling additional wells in order to provide the open flow required, and the additional cost of operating wells at low pressures.

The price paid by those purchasing gas at the well for pipeline uses has progressed along with these royalty schedules. I recently had occasion to make an analysis of prices paid for gas in the field. The average is slightly above four cents, which vindicates our judgment in establishing the four cent price in our royalty division order. It is my judgment that as the pressures go down and the cost of producing gas goes up, the field price of gas will continue to increase, and on that basis we have contracted with our royalty owners to pay them at the increased schedules of prices.

I have made a study and a computation of the past, present and future withdrawals of gas by the different pipeline companies taking gas from that field. With respect to their past production and their present rate of withdrawal, I obtained some information from the companies themselves and additional information was obtained from the records of the Texas Railroad Commission. In determining the probable future withdrawals by the pipeline companies, I have given consideration to the supply of gas available, to the capacity of the pipeline under consideration, and to the markets which are available to these lines.

Taking first Texoma's pipeline, it is our judgment that the withdrawals of Texoma will not be larger than they have been in the past, because Texoma is now operating about at its capacity. There will be some increase of gas withdrawn from the field on account of increased use of fuel by field compressor stations. The capacity of the pipeline is not estimated to change over what it has been for the past three years.

460 By "field compressor stations" I mean what are commonly called booster stations. We have already installed one booster station, and we will install others at the points where they are needed as the pressures in the field decline. That is for the purpose of boosting the gas into the Fritch gasoline plant and on into the main pipeline. In other words, Fritch station does not have the capacity to take gas at low pressures and to boost it to 710 pounds pipeline operating pressure. We will have to maintain a certain level of pressure at Fritch, and this level will be maintained by these field booster stations. The engines driving these field compressors will be fired by gas, which is what I meant by increased use of gas. This additional fuel requirement is the only increased use of gas which we contemplate so far as Texoma is concerned. We estimate that in 1943 Texoma will produce 52,452,326,000 cubic feet of gas, and that the production will continue approximately the same during the period from then on.

The Canadian River Gas Company supplies 25% of Natural Gas Pipeline Company's requirements, and the same conditions will apply to their withdrawals as those discussed concerning Texoma. In 1943 Canadian River will supply 17,229,985,000 cubic feet. That is supplied to the Natural Gas Pipeline Company and is not included in the 52 billion.

I have also made a study concerning the problem of future withdrawals of Canadian River Gas Company outside of those it will supply to Natural Gas Pipeline Company. Canadian River's Denver line and the local line have a combined capacity of 56 billion cubic feet annually. In the past, in 1932, these lines withdrew approximately 15 billion cubic feet. This declined to something over 13 billion cubic feet in 1933, and then gradually increased to more than 23 billion in 1937. In 1938 something over 21 billion was produced, and we estimate that by 1941 something over 23 billion will be produced annually.

(Document entitled "Withdrawals of Gas," marked Exhibit 87 for identification.)

In considering the withdrawals of Canadian River Gas Company we have estimated no increase in load for the Denver line over its record for the past three years. However, we do estimate a small increase in use by the city of Amarillo, due principally to the continued growth of this town.

Exhibit 87 is now presented to me. The chart shown on

the first page shows the withdrawal of gas by years in billions of cubic feet. The solid black line shows the actual withdrawals from 1932 to 1938, and the dotted line shows the estimated withdrawals from that point forward. Also on the chart is a solid black line showing the capacity of the pipeline in billions of cubic feet annually.

The figures along the left side of that chart represent the withdrawals in billions of cubic feet per year at 16.4 pounds pressure base. The figures along the bottom of the chart represent the years, starting in 1932.

My figures were obtained largely from records of the pipeline companies themselves and were supplemented by information from the Texas Railroad Commission, from reports which were filed by these companies as to their actual production. The Railroad Commission records would show, for example, in the year 1937, the actual production by Canadian River Gas Company. It was
461 necessary for us to consult the Railroad Commission records because some of the records of the pipe line companies in the earlier years were not available, and we had to use both sources of information. They are identical, however.

I have estimated the future load of Canadian River Gas Company in conjunction with the Colorado Interstate Pipeline Company to be only a little over 22 billion cubic feet annually, although it has a capacity to handle 56,575,000,000 cubic feet annually, because the withdrawals of this pipeline are going to be determined by its market, and an analysis of its market situation indicates that there won't be any substantial increase in load because the territory which they serve is very well occupied at the present time and has no particular indication at this time of appreciable growth. So far as their immediate prospects are concerned, I do not believe they will be able to fill that line with gas to those market outlets.

The Colorado Interstate Gas Company is the correct name, not Colorado Interstate Pipeline Company. It is the same company from which Natural Gas Pipeline Company buys one-fourth of its market requirements.

On page 2 of Exhibit 87 are two charts. The first chart, occupying the upper half of the page, portrays the actual and estimated withdrawals of the Lone Star Gas Company. This pipe line serves principally the north Texas area around Fort Worth and Dallas. It has a capacity of 18,250,000,000 cubic feet annually. In 1932 it withdrew a

little over seven billion. This declined in 1933 to about six billion, and then increased to eight billion for 1934 and 1935; declined in 1936 to a little over seven billion, and then has shown a gradual increase since that time. We estimate that future withdrawals of the Lone Star will amount to 10,500,000,000 cubic feet annually. This increase in withdrawals will be necessary on account of the growth of the area served by the pipeline. Good labor conditions and favorable fuel conditions have increased the industrial development of this particular area and these towns have grown considerably since 1936.

There has been an uptrend during the last two years, as shown on the chart. This estimated withdrawal is almost eight billion cubic feet annually below the capacity of that line, and it is serving the important cities of Dallas and Fort Worth in northern Texas.

The figures along the left side and bottom of that chart have the same meaning that they do on the chart on page 1; and that is also true of the other charts that have to do with pipelines in the first six pages of this exhibit.

The chart at the bottom of that page shows the actual and estimated withdrawals of West Texas Gas Company. That is the company which delivers gas to a large area in west Texas south of Amarillo. It includes the towns of Plainview, Lubbock, Big Springs and San Angelo. You will notice from the chart that this pipeline has steadily increased its withdrawals since 1933. We estimate that this trend will continue until 1942, and that future withdrawals by the West Texas Gas Company will amount to eight billion cubic feet annually. The capacity of the line is 12,775,000,000 cubic feet annually. My judgment is that the requirements of that line will not exceed 8 billion of its capacity of 12,775,000,000 cubic feet annually.

462

The chart on page 3 of this exhibit shows the withdrawals of Cities Service Company, actual and estimated. This pipe line during 1938 operated very closely to its capacity and we do not estimate that the future withdrawals will increase appreciably. In other words, we estimate that the future annual withdrawals will be 42 billion compared to a capacity of the pipeline of 45,625,000,000, leaving a margin in that line of about 3,600,000,000.

When I speak of capacity on the first six pages of Exhibit 87, I refer to a 100% load factor.

Page 4 represents the actual and estimated withdrawals

of Panhandle Eastern Pipeline Company. This pipeline serves towns and cities in Missouri, Illinois, Indiana, Ohio and Michigan. Its principal outlet will be the Detroit area. You will note from the chart that there has been a steady and consistent increase in withdrawals by this pipeline. During recent years this company has looped its pipeline system one-half the distance between compressor stations from Liberal, Kansas, to the Indiana line, and we estimate that this trend of increase in production will continue until 1942, when total withdrawals will reach 44 billion cubic feet annually. The capacity of the pipeline system is 54,750,000,000. We consider that the Panhandle Eastern Pipeline Company has one of the best opportunities of any pipeline for increasing its load, principally on account of the industrial business that is available in the Detroit area and vicinity. That line has not been in Detroit since 1932. I believe it has been in there about a year.

Questions by the Examiner.

When I make the estimate in my market study, for example, with reference to the Detroit area, it includes possibilities in addition to the Detroit area. I mentioned it as having the best opportunities. That line has a possibility of serving Indianapolis. It has just recently tied to a number of towns in northwestern Ohio, and is extending its service to southern Michigan, I believe to Grand Rapids, and a number of those towns in the southern part of the peninsula there. It has possibilities for increase in load both for domestic and industrial. I considered all those factors, including the possible extension of lines. When Panhandle Eastern loop this line they increase their capacity 25%. The completion of the looping, which will cost just the same as the amount of looping they have done now, will increase that capacity 75% more; so you can visualize that they will go ahead and complete the looping of the line. It is almost an economic necessity. That 54,750,000,000 does not consider the looping.

Direct Examination Resumed by Mr. Morgan.

As to whether it is my view that 44 billion cubic feet annually is the limit of its possibility, it is possible for this pipeline to produce more gas than this. I have taken into account the fact that the load factor will have some bearing on the total withdrawals. It could with any improvement

in that condition carry right on through to larger amounts,
and I have given weight to the question of capacity, the
463 potentialities of those markets, and the very perceptible upward trend that has prevailed with respect to this pipeline from the beginning. Another important point on this estimate of withdrawals from the Panhandle is that Panhandle Eastern takes about 25% of its requirements from the Hugoton field and 75% from the Texas Panhandle. This exhibit shows just the withdrawal from the Panhandle.

Turning now to page 5 of this same exhibit, Northern Natural Gas Company has a capacity of 47,450,000,000 cubic feet annually. This line serves towns in Nebraska, Iowa, South Dakota, and Minnesota. Its principal outlets are Omaha, Lincoln, Des Moines and the St. Paul and Minneapolis area. This line was just recently extended to the St. Paul-Minneapolis area, and you will note from the chart that there has been a consistent increase in load with a slight falling off in 1935, then the trend of increase continues to 1938. We think that this pipeline has very good possibilities for continued growth, particularly in the St. Paul-Minneapolis area. An evidence of this fact is that this company is now building a 16 inch line from Sioux City, Iowa, to the St. Paul-Minneapolis area. That is an additional line, and we estimate that by 1942 this line will withdraw from the Panhandle field 36,500,000,000 cubic feet annually. I had in mind the possibilities of more production than this, but I recently had occasion to consult with the engineers who are making an investigation for the financing of this new line, and they have placed the withdrawal estimate from the Panhandle field at the figure of 36,500,000,000 cubic feet annually, and I have adopted that figure. That figure includes the new line in question. The new line only increases the capacity at the upper end. It does not affect the total capacity of the system. They have a larger capacity part of the way up.

Cross-Examination Interposed by Mr. Slaff.

Northern Natural also withdraws from the Hugoton field. I don't have the figures as to the percentage of their requirements which they take from the Hugoton field. The connected open flow in Hugoton is about half of the connected open flow in the Panhandle, but I do not

have in mind the percentage of withdrawal figures. I believe that they withdraw about 65% from the Panhandle and 35% from Hugoton. I don't know whether they contemplate maintaining substantially the same portions in the future. I think the possibilities are that they will increase the percentage from the Texas Panhandle. The estimate I have made on withdrawals covers just what they will take from the Panhandle field.

Direct Examination Resumed by Mr. Morgan.

The past withdrawals reflected by this chart have to do with the Panhandle annual withdrawals only.

Page 6 of this exhibit shows two charts. The first chart shows the estimated and actual withdrawals of the Texas Panhandle Gas Company, which is now known as Consolidated Gas Utilities Corporation. This line serves towns in Oklahoma and Kansas, and has a capacity of 12,775,000,000 cubic feet annually. The chart indicates that this pipe line has had larger takes in past years than it has at present. We estimate that there will be no increase in takes over the average for the last three years. As a matter of fact, we estimate the load will
464 decline somewhat. The withdrawals of this line will be governed primarily by its market outlet. It has plenty of capacity but not the market.

The Northern Texas Utilities Company is shown on the chart at the bottom of the same page. This line has a capacity of 15,330,000,000 cubic feet annually. Its withdrawals have shown a gradual and a consistent growth, which we estimate will continue until about 1940. This line serves Wichita Falls and vicinity. There has been a large development of deep oil production in the vicinity of Wichita Falls which has affected the growth of this community. This oil production is encountered without the presence of any marketable gas and there has been a good deal of gas sold for drilling operations, and it will continue to be sold for that purpose, and the growth of the general area has increased the domestic consumption of gas. I think it will level off at about eight billion for the remainder of the life of the field, with a capacity of fifteen and a third billion annually.

All of these pipelines and those who produce gas and sell to these pipelines are confronted with the necessity

of utilizing additional fuel gas in the operation of booster stations, just like Texoma. Some of them, Cities Service, Lone Star and North Texas Utilities, have already installed booster stations and have them in operation now.

I have tabulated these estimated withdrawals of gas by the pipe lines in addition to the information reflected by the charts on the first six pages of this exhibit.

(Document entitled "Texas Panhandle Field; Estimated Future Withdrawals of Gas," marked Exhibit 88 for identification.)

Exhibit 88 is a tabulation prepared by me of the pipeline companies, and shows by years from 1939 to 1943 the estimated withdrawals of gas. Those are the same withdrawals reflected on these charts for the companies for which the charts have been prepared.

Where I have "Local, 890,000 MCF annually," that designates a local gas company serving the eastern part of the Panhandle field. The town of Shamrock is included in its market. I do not predict any increase for that company and other local companies. The 890,000 MCF for local companies represents their present withdrawals.

I did not extend beyond 1943 in the tabulation and charts because this estimate of withdrawals is expected to cover the period of growth in the pipeline companies' markets, and we anticipate that production will level off at about the year 1943. We do not anticipate and have not provided in our estimates for any increase beyond that year. Then I think they will continue to produce that quantity from the field as long as that quantity is available to them. There is some reason to believe that these quantities may increase beyond that period, but we have taken a conservative view of it, and have assumed a continuation of the rate we believe will prevail at that time for such period as we believe the gas will be available.

The chart on page 7 of Exhibit 87 shows the gas
465 used by gasoline plants and carbon black plants in the Texas Panhandle field. The withdrawals of gas to gasoline plants is determined in large measure by the withdrawals of gas for use in the manufacture of carbon black. That has not always been the case. By reference to the chart you will notice that during 1933 to 1936 a very large withdrawal of gas was made to gasoline plants that is not reflected in the use of gas for carbon black. It was due to the excessive stripping of gas for gasoline

content and blowing the residue to the air. The chart shows that there has been gradual increase in the use of gas for carbon black from 1932 to 1938 with a peak demand for gas for this use in 1937. During 1937 carbon black stocks were built up and we considered it an abnormal year on that account. Stocks have been reduced during 1938, and the trend during the early part of this year indicates a resumption of the upward demand for gas for this use, and we estimate that by 1941 the demand for carbon black will reach a little over 280,000,000,000 cubic feet annually.

The total capacity of the existing carbon black plants in the Panhandle field is 321,000,000,000 cubic feet annually. During the last three years a number of plants have been built in the Panhandle, and some of the existing plants as of three years ago have been increased in capacity. I have no reason to think that there will not be other plants constructed down there. I think the construction of plants will be governed largely by the demand for carbon black. There is ample gas available under the law in the field for the expansion of the carbon black industry, beyond the figures which I have estimated.

Questions by the Examiner.

The principal use of carbon black is in the manufacture of automobile tires. Possibly 90% is for that use. Possibly 6% is used for the manufacture of ink, and there is a small amount that goes into paints and some miscellaneous uses. The principal outlet is for automobile tires. It is also used for rubber goods in general, belts, garden hose, overshoes, etc. It has the quality of increasing the elasticity and resisting qualities of the rubber. As compared with the old white tire we used to use prior to the introduction of carbon black into that fabric, an automobile tire now will last about four times as long, and this quality is largely due to the inclusion of carbon black in its manufacture. The rubber industry for the same purpose use a different kind of carbon black. It is still a product of similar quality, and comes from gas. Apparently there is not any substitute for it that they know of now.

Direct Examination Resumed by Mr. Morgan.

The future increase in the production of gas to gasoline plants, as appears on this chart, is approximately the same as the increase in the demand for gas to be used in the manufacture of carbon black. All of the gas processed by gasoline plants is not available to carbon black plants for the manufacture of carbon black because some gas is used up in the manufacture of gasoline. Some gas is used for fuel for the gasoline plants, and a considerable quantity of gas is returned to the leases for lease fuel, and it is the residue that is left that is available for carbon black, and there will always be more gas run to gasoline plants than is used by carbon black plants.

466 In the Panhandle, where you find a gasoline plant you will find a carbon black plant close beside it, or a pipeline. This pipeline gas is also processed, but that is not included in my figures. They are not mutually inconsistent by-products in any way. You can take gasoline out and then take the carbon black out.

Counsel has suggested that there are only certain kinds of gas, namely, casinghead gas in oil wells and sour gas, which under the laws in Texas may be used in the manufacture of carbon black, and that is the thing that limits the run to the kind of gasoline plant we are talking about here to that quantity of gas which is burned in the manufacture of carbon black, plus the plant loss and the quantity used for fuel purposes and things of that sort. Taking gasoline out of natural gas has the effect of reducing the carbon black recovery, but the gasoline is a more important product financially than the carbon black manufacture.

I have been asked to explain the relationship between the users of gas for carbon black and those who operate gasoline plants. The gas is processed for its gasoline content in the gasoline plants before any residue is delivered to the carbon black plants. This processing of the natural gas for gasoline is a more profitable operation than use of the same amount of gas for the manufacture of carbon black, and the Texas statutes require that the gasoline be extracted before the gas is used for the manufacture of carbon black. The residue gas which is delivered to the carbon black plants is burned in an atmosphere which is deficient in oxygen. This has the effect of

forming lamp black, the same principle as when the old kerosene lamp would form a black on the chimney. This lamp black or carbon black, after it has been deposited in the channels, is scraped off and collected for shipment. The process of manufacturing carbon black from natural gas entirely consumes the residue gas.

There is a possibility of an increased efficiency in the production of carbon black which would require a smaller volume of gas. There is a process for manufacturing black which is more efficient than the channel process, but the qualities of the black manufactured are not the same. The tire manufacturers and the rubber manufacturers still require black made by the channel process, although there is a market for some of the other black which I have mentioned, which is marketed under the name of Gas-tex.

There is a limited market for the product that is more efficiently recovered, that is, recovered in larger quantities for volume of gas consumed.

(At this point, in response to a question by the Examiner, counsel for defendants stated that under the Texas statutes the two industries referred to are necessarily related; that the gasoline plant cannot process for gasoline unless it has an outlet for carbon black because they won't allow this residue to be popped to the air any more, and the carbon black manufacturer is not allowed to use this gas unless he first strips the gasoline out of it, and, therefore, they are inseparably tied together from both ends, and each must have the other one to do business.)

467 In connection with what I have said I would like to add one more statement, and that is, as the field becomes older the gas which is returned for lease fuel will probably increase due to the aging of the field fuel lines and the consequent leakage of gas that occurs in lines which have been laid as these lines are laid—usually out of second-hand pipe and usually put in under the stress of rapid developing operations. This gas returned for lease fuel is not charged for, and there is no particular incentive on the part of the field operators to keep these field lines in condition. I have not added anything to my estimates on account of that situation.

On Exhibit 88 I have shown the quantity of gas which will probably be used by gasoline plants, a portion of which is run to carbon black plants, as reflected on page 7 of Ex-

hibit 87. We show that in 1939 the gas to gasoline plants will amount of 341,384,800,000 cubic feet annually.

The gasoline extraction process doesn't change the gas itself except that it reduces some of the heavier hydrocarbons—I mean some of the hydrocarbons that decrease the quantity of the gas by the amount that those hydrocarbons represent. Theoretically, the natural gas would be stripped for gasoline even though it is in the dry state in the non-oil bearing part of the field. The dry gas in the Panhandle field has a gasoline content of one-third of a gallon per thousand cubic feet, and that is worth trying to extract. Normally, casinghead gas contains above a gallon per thousand cubic feet. That was the reason for this upturn of the curve of gas running to gasoline plants in 1934 and 1935. They were stripping gasoline from dry gas and blowing the residue to the air. It was quite profitable when consideration was given to the volumes that were used at that time.

This estimate of gas for 1939 compares with 318,498,051,000 in 1938 and 345,298,466,000 in 1937. We estimate an increase yearly of use of gas by gasoline plants until 1941, when 384,057,000,000 cubic feet will be used. That quantity is projected on through the period when it would be available according to my estimates. I select that as a top figure because it is controlled principally by what we think the top figure in the use of gas for carbon black will be, and that is still well below the present carbon black capacity.

That is in effect merely following the upward trend on gas used for carbon black which has obtained from 1932 to the end of 1938, on through three more years. As I explained this morning, in 1937 an excessive amount of gas was used for the manufacture of carbon black. This is indicated by the curves, and this excessive use of gas resulted in a substantial increase in carbon black stocks. This had the effect of bringing about a reduction in the price of carbon black and curtailment in the use of gas for its manufacture in 1938. During this period carbon black stocks were reduced, and the trend of use of gas for carbon black manufacture during 1939 is again upward and there is a consistent increase in the use of gas for carbon black manufacture since 1932 to the present time. Aside from the
468 gable or hump extending up through the year 1937 and slightly downward in 1938, this main projected line for the next three years represents a mere continuation of the

trend, the upward trend, of that character of consumption of natural gas that has been occurring for the past several years.

In addition to the gas used by pipelines and that used by gasoline plants and carbon black plants, I have included on Exhibit 88 two other uses.

One is the casinghead gas blown to the air from oil wells not connected to gasoline plants. This estimate is based on the number of oil wells not connected to gasoline plants, and we estimate it to be five billion cubic feet annually. That is the same as the withdrawal at the present time for that item. It is a good deal smaller now than it has been, due to the fact that the gasoline plants have connected through to all the wells that it is economically feasible to connect. The amount of gas used or withdrawn under this classification in 1932 we estimate was 32 billion; 1933, 25 billion; 1934, 33 billion; 1935, 28 billion; 1936, 15 billion; 1937, six billion; and in 1938, 5,075,000,000. That figure has been coming down because the gasoline plants have connected more and more wells that were economically feasible to connect, and a great number of the wells that are connected are located along the marginal area between the oil and gas zones. My figures are based entirely on estimates, as none of this gas is measured. They are Mr. Peterson's estimates, made under my direction, and taken from his Exhibit 25.

The other use of gas which I include is gas used for fuel and wastage through the air from drilling wells. This estimate is based on 1938 withdrawals for this purpose and consideration was given past experience. We estimate approximately twelve billion cubic feet annually will be withdrawn in this manner. In 1932 approximately four billion was used in this manner; and in 1933 the same. This was during the depression when approximately no drilling was going on and that figure would obviously be low. In 1934 it was 21 billion; 1935, 26 billion; 1936, 30 billion; 1937, 29 billion; and in 1938, 12,268,267,000.

This estimate on gas used for this purpose was based on a study by Mr. Peterson of the scout reports. He tabulated the number of wells drilling, the number of days drilling, and the number of days drilling in the pay horizon, consideration being given to the open flow of the wells as reported by the scout reports. It was a very carefully prepared estimate and I think it is fairly reliable.

In my judgment, the total gas withdrawals or require-

ments of the various pipelines, gasoline plants, and other needs and uses covered by Exhibit 88 will probably level off by the year 1942 at 651 billion cubic feet annually. The same reason obtains for not projecting this total on to the future as that stated with reference to the pipelines. It is my view the requirements will equal those quantities as long as the gas is available for them.

On the last page of Exhibit 87 there is still another 469 chart, captioned "Total Past and Future Production from Texas Panhandle Gas Field." This chart represents on the vertical scale at the left the withdrawal of gas in trillions of cubic feet at 16.4 pounds pressure base. At the bottom of the sheet are designated the years beginning in 1926, which is the time the field broke out in earnest. The legends or expressions showing reserves to zero pounds abandonment, to 25 pounds abandonment, and so on, in the upper left hand corner of the chart represent Mr. Peterson's estimate of the reserves in the field at different abandonment pressures. They are plotted on the scale of trillions of cubic feet of gas annually. The figures are Mr. Peterson's estimates after he applied a 90% recovery factor to his estimate of the original reserves in place.

The oblique line, which is solid a part of the way and broken the remainder of the way, from the lower left hand corner across to a point near the upper right hand corner of the chart, represents the actual accumulated production from the Panhandle field by years through 1938 where the line is solid, and the dotted line represents the projection of our annual estimates of future gas withdrawals from the field.

To the accumulated production down to and through 1938 I added the estimated gas withdrawals for 1939, as reflected on Exhibit 88, and in that way built up annually on across the page by adding to the production as of the end of one year my estimate of the production for the following year. That line naturally shows an increase in volume at the end of each year. That is substantially a projection of the actual withdrawals from year to year all across the page.

Following that projected line on to the right and upward in its course, the accumulated withdrawals will use up all of the recoverable gas down to 100 pounds assumed abandonment pressure early in the year 1948.

According to my judgment, the estimated withdrawals will use up all the recoverable gas to an assumed abandon-

ment pressure of 75 pounds late in 1949. Those withdrawals would use up all the recoverable gas to an assumed abandonment pressure of 50 pounds early in 1951. They would use up the recoverable gas to an assumed abandonment pressure of 25 pounds late in 1952. The total recoverable gas down to an assumed abandonment pressure of zero pounds, if it were possible to withdraw it down to that point, would be consumed early in 1954.

The four broken heavy lines across the top of the page are based on Mr. C. J. Peterson's estimates of recoverable reserves, and the solid line representing the accumulated production is based on Mr. Peterson's estimates. Those are the estimates reflected in Exhibits 28 and 25 respectively.

Questions by the Examiner.

In connection with Exhibit 87 I explained what the data for the actual withdrawals for the Canadian River Gas Company were based on. That is the same type of data used in connection with each of the other graphs, the Lone Star Gas Company, and so on. In other words, I used 470 the reports of the Texas Railroad Commission plus the data I got from each of the producing companies. It would include the total amount of gas from the field, the data being obtained either from the companies themselves or from the Texas Railroad Commission. It includes the gas produced and also the gas purchased by those companies, if they produced and purchased both.

The figures for the Canadian River Company and West Texas, and so forth, on Exhibit 88 are the same as I drafted for Exhibit 87 in each case.

(EXHIBITS 87 and 88 for identification, offered and received in evidence without objection.)